AN ENGINEERING AND ECONOMIC ANALYSIS OF A STEAMFLOOD PLUS SURFACTANT FIELD PROJECT

A REPORT

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ABSTRACT

In 1980, the Stanford University Petroleum Research Institute embarked on a field project designed to test the effectiveness of the surfactant Suntech IV in overcoming gravity override and channelling during the steam injection process. This test was completed in December of 1983, and proved to be successful.

The purpose of this study was two-fold. First, an attempt was made to accurately calculate the incremental oil produced due to the surfactant. This was done using two well known analytical steamflood models, the Marx and Langenheim frontal displacement model and the Vogel overlay model, for the purpose of establishing a baseline production curve without surfactant. The Marx and Langenheim model produced reasonable results well in line with those obtained via simple extrapolation of the pre-test decline curve. The Vogel model, on the other hand, gave no relevant results and was deemed inapplicable to this reservoir.

The second part of this study dealt with the economic feasibility of a steam plus surfactant injection project. An economic analysis was performed on the pilot project, and a net loss of money was determined. Next, a scenario for a commercial scale implementation of the steam plus surfactant system was hypothesized and analyzed. Three different levels of incremental oil produced were tested, and in each case overwhelming financial success resulted.

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1. INTRODUCTION AND PROBLEM STATEMENT

As the era of hydrocarbon fuels reaches its mature stages, the problem of increasing recoverability from known deposits of oil and gas has become a critical point of focus for the petroleum industry. Nowhere is this more apparent than in the heavy oil reservoirs of California, where upwards of 90%-95% of the original oil in place is left behind by primary recovery mechanisms. Heat injection, in the form of hot water, steam, or in situ combustion, has proven to be a valuable tool for secondary recovery in this region. The effect of injected heat is viscosity reduction, thereby allowing greater mobility of oil and, ultimately, increased cumulative production. When steam is used as the heat injection medium, however, two phenomena often lead to poorer than desired recovery efficiency. One is due to the fact that steam is lighter than oil, and tends to float to the top of the formation. This phenomenon, called gravity override, causes decreased contact between steam and oil, and therefore less viscosity reduction. The second problem results from steam's greater mobility than oil. This results in steam channels within the reservoir, and again allows steam to flow from injection well to producing well with less effective heat transfer.

In 1980, the Stanford University Petroleum Research Institute embarked on a field project designed to test the effectiveness of the surfactant Suntech IV in reducing gravity override and channeling in steam injection. It was theorized that the surfactant, upon injection into the reservoir with steam, would create a foam that would partially block the highly permeable steam filled channels and force a more even distribution of steam across the entire reservoir thickness. After extensive laboratory testing to optimize the conditions of injection, three separate slug tests were performed on a five spot test pattern in the McManus Lease in the Kern River Field. Brigham, Marcou, Sanyal, Malito, and Castanier (1984). give a detailed description of the methodology and results of this pilot.

It will suffice to say here that all test results indicated a successful experiment. Injectivity profiles run before and after slug injections showed more evenly distributed injection profiles. Also, decline curve extrapolation of the pre-injection production curve showed 14,000 to 31,000 barrels of incremental oil production.

The purpose of this report is an examination of the economic outcome of such a steam and surfactant injection system, both on a pilot scale and on a lease-wide commercial scale. In order to do this, the critical parameter of incremental oil production had to be as firmly established as possible. Thus, the first half of this report deals with analytical steamflood modelling. Using historical injection and production data for the entire McManus Lease, several analytical steam flood models were tested. Once a reasonable fit was achieved, the model was applied to the pilot test pattern. In this way, it was hoped that an accurate baseline production curve could be formed from which the incremental oil due to the surfactant could be calculated. This endeavor was partially successful as described in Section 2.

The latter half of the report deals with the economic evaluation. First, the pilot economics were briefly examined. Following this, a lease-wide economic evaluation was performed. The necessary equipment and methodology for such a program were designed and priced. Incremental oil production, based on conclusions from the first part of the report and extrapolated to an entire lease scenario, was also identified. Results and discussion of these analyses are presented in Section **3.** Finally, conclusions and recommendations are given in Section 4.

2. STEAMFLOOD PREDICTION MODELS

2.1 Literature Survey

As the first part of this report deals with history matching of steam injection-oil production data, it is relevant at this point to present a brief review of the literature concerning this technology. For any thermal recovery project in which heat is injected into the reservoir from the surface, three realms of heat loss must be considered: heat loss from surface lines, heat loss in the wellbore, and heat loss within the reservoir. In this project, I have made the assumption of negligible heat losses in the surface line. Furthermore, heat losses in the wellbore were calculated using a computer program written by Osman Karaoguz (1984), a graduate student in Petroleum Engineering at Stanford. His Masters' Report provides a complete review of the wellbore heat loss literature. This topic, therefore, will not be discussed here.

The classical treatment of the reservoir heat loss problem was performed by Marx and Langenheim (1959). Assuming the temperature rise in the heated zone to be a step function, they solved the heat balance differential equation and found both the areal extent of the heated zone as a function of time, and the rate of growth of the heated zone as a function of time. Initially, they made the assumption of constant rate steam injection. Ramey (1959), however, showed by the use of the superposition integral how to handle the case of variable injection rates. In addition, he pointed out the generality of their solution; it is applicable not merely for the radial flow case, but for any generalized steam zone shape.

Prats (1969), expanding upon the work of Marx and Langenheirn, was able to **extend** their results to less restrictive conditions. He was able to show that the critical injection parameter is not temperature or steam rate, but rather heat input rate. Furthermore, this heat input rate is net rate, meaning heat input at the sandface less heat lost through produced fluids. **A** second contribution by

Prats was relaxation of the Marx and Langenheim assumptions of heat loss to the adjacent formation in one-dimension only (vertical), and only through convective mechanisms. He showed that their solutions hold true for three-dimensional heat loss by both conduction and convection.

Marx and Langenheim and Prats both held the underlying assumption of a step function temperature distribution in the reservoir. Easing of this assumption, and attempting to correlate the true horizontal temperature distribution in the reservoir, is the first step toward predicting. heat losses through produced fluids. Lauwerier (1955) did just this for hot water injection into a linear system, with vertical heat losses by conduction only and heat transfer within the reservoir by convection only. Interestingly enough, his work, and the analogous work of Malofeev (1960) for radial systems, both bear out Marx and Langenheims' result for heat loss to adjacent formations, despite the variation of temperature in the horizontal direction.

A further problem not considered by Marx and Langenheim is the presence of a condensed region just ahead of the steam zone. Baker (1969) proved the existence of such a zone experimentally using a reservoir model of thickness 4 inches and diameter 6 feet. Injecting steam at ratio of 22 to 299 lb/hr ft, he found the presence of a hot water zone ahead of the steam front, as well as a considerable amount of gravity override of injected steam.

Several authors have attacked the problem of this condensed zone, and how it affects the heating efficiency of the injection process. Satter and Parrish (1971), extending the work of Wilson and Root (1966), included this hot water zone in their numerical solution of the relevant heat balance equations. Their results were similar to Marx and Langenheim's in total heat remaining within the reservoir, but differed in how that heat is distributed. Prats (1969) derived a solution to this problem in terms of an upper and lower bound for the thermal efficiency, defined as the percentage of heat injected into the reservoir which remains in the reservoir. Mandl and Volek's (1969) solution is important in that it defines a critical time after which the hot water zone develops. Prior to the critical time, Marx and Langenheim's solution applies. Afterwards, an upper and lower bound efficiency may be calculated, the upper bound being, again, the Marx and Langenheim solution. They suggested that for the purposes of heat loss calculations, an arithmetic average of the bounds be used as a viable approximation. Myhill and Stegmeir (1978), noting a mathematical inaccuracy arising from a simplifying assumption made by Mandl and Volek, modified the lower bound solution. In addition, they suggested a different weighting factor for the averaging, one that ensures a zero efficiency if steam injection is terminated.

Once correlations for the prediction of heat losses in reservoirs were established, prediction of oil recovery based on these correlations followed. The simplest methodology (and the one that is utilized in this study) presumes that all heat remaining in the reservoir occupies a single steam zone at a uniformly elevated temperature. Within this zone, residual oil quickly reduces to some low, irreducible level. Thus, knowledge of the size of this zone (attained through the aforementioned heat loss calculation and thermal properties of the reservoir), coupled with an empirical approximation of the residual oil saturation, allows one to predict oil production with time. The simplifying assumptions critical to this methodology are not without experimental and theoretical verification. The work of Willman, *et al.* (1961) experimentally established the mechanism of oil displacement by steam and hot water. Significantly, while both involve viscosity reduction (to improve mobility) and thermal oil expansion, steam provides a distillation effect which quickly reduces oil saturations to near zero levels. While this distillation effect is not nearly as pronounced with heavy oils, Wu and Brown (1975) showed nonetheless that it exists. Modelling the steam zone growth as a piston-like displacement is the second simplifying assumption. Experimental studies by Schenk (1965) using heavy oil in a linear prototype resulted in a stable steam front of just this type. Analytical modeling by Miller (1975) of water displacement by steam in porous media provided theoretical justification of these experimental findings.

More recently, researchers have attacked the obvious deficiencies inherent in these simple methodologies. As proven by Baker (1969) gravity override by steam during an injection process can occur. This phenomenon of steam zone growth in the form of an overlay conflicts with the piston-like displacement assumption utilized in the previous heat loss and recovery models. By far the simplest model accounting for gravity override is that of Vogel (1983). Vogel assumed a virtually instantaneous overlay of steam, with subsequent steam zone growth in the vertical direction only. In addition, he assumed that the rate of growth would be slow enough to justify considering it a stationary plane. With this in hand, he applied the well known solution of heat loss from an infinite plane to derive his heat efficiency function. This work was, in fact, a simplification of an earlier model proposed by Neuman (1975a,b). Neuman relaxed the assumption of instantaneous steam overlay while retaining the stationary plane assumption. His resultant heat balance equations describe steam zone growth in both the vertical and horizontal direction, hence producing a system in which the steam zone overlays the reservoir and grows downward simultaneously. Finally, Doscher and Ghassemi (1981) attacked the problem in much the same manner as Vogel. Rather than assume a stationary plane, however, they solved the problem of heat loss from a descending plane.

The latest steam flood technology attempts to incorporate fluid flow principles into the already established heat balance scenarios in order to get a more exact picture of the steam zone shape and interactions as it develops. Analytical models such as those proposed by Van Lookeren (1977) and Aydelotte and Pope (1982) as well as numerical simulation models to numerous to mention, are examples of the this state of the art approach.

2.2 Models Utilized in This Study

Two of the simplest models available were chosen for testing in this study: Marx and Langenheim's frontal displacement model (with Ramey's modification for variable rates), and Vogel's steam overlay model. It was felt that data control for the pilot was not sufficiently precise to warrant either the time or effort necessary for the application of more sophisticated methods. The existence of highly variable heat injection rates further complicated the situation, since the more complex models were all derived on the basis of constant rate injection only.

2.2.1 Marx-Langenheim

The Marx and Langenheim model employs a direct heat balance between net rate of heat input to the formation, the rate of heat transfer within the formation, and the rate of heat lost to the overburden and underburden. The schematic in Fig. 2.1, reprinted from Myhill and Stegmeir (1978) shows the details of this process.

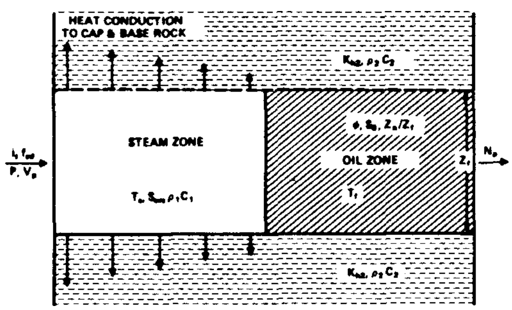

Fig. 2.1 Frontal Displacement Steamflood Model

In the nomenclature of Prats (1982) this balance may be expressed as

$$Q_i = M_R h_t \Delta T_i \frac{dA}{dt} + Q_l \tag{2.1}$$

Q_i is the heat injection rate, M_R is the volumetric heat capacity of the reservoir, h_t is the formation thickness, and ΔT_i is the rise in temperature of the formation above the ambient reservoir temperature. $\dot{Q}_l$, the rate of heat lost by conduction to the overburden and underburden, is defined by

$$\dot{Q}_l = 2 \int_{\lambda=0}^{\lambda=t} \left[\frac{K_s \Delta T_i}{\sqrt{\pi \alpha_s (t - \lambda)}} \right] \left(\frac{dA}{d\lambda} \right) d\lambda \tag{2.2}$$

K_s and a, are thermal conductivity and thermal diffusivity of the adjacent zones, respectively. For this formulation, no vertical temperature variation is assumed within the reservoir, and horizontal variation is represented by a step function.

The solution of **Eq.** (2.2) yields the areal extent of the heated zone as a function of time

$$A(t) = \left(\frac{\dot{Q}_i M_R h_t \alpha_s}{4 K_s^2 \Delta T_i} \right) \left(e^{t_D} erfc \sqrt{t_D} + 2 \frac{\sqrt{t_D}}{\pi} - 1 \right) \tag{2.3}$$

Dimensionless time, t_D, is defined as

$$t_D = \frac{4 K_s^2}{M_R^2 h_t^2 \alpha_s} t \tag{2.4}$$

Applying the equivalence relationship

$$\frac{K_s^2}{\alpha_s} = \alpha_s M_s^2 \tag{2.5}$$

gives the final form presented by Prats (1982)

$$A(t) = \frac{\dot{Q}_i M_R h_t}{4\Delta t_i \alpha_s M_s^2}\left[e^{t_D} \, erfc \, \sqrt{t_D} + 2\sqrt{\frac{t_D}{\pi}} - 1\right] \tag{2.6}$$

Differentiation with respect to time yields the rate of growth of the heated zone.

$$\frac{dA}{dt} = \frac{Q_i}{\Delta T_i M_R h_t}\left[e^{t_D} + erfc \, \sqrt{t_D}\right] \tag{2.7}$$

Finally, the heat remaining in the reservoir at any given time may be expressed as

$$Q(t) = \frac{\dot{Q}_i M_R^2 h_t^2}{4\alpha_s M_s^2}\left[e^{t_D} \, erfc \, \sqrt{t_D} + \sqrt{\frac{t_D}{\pi}} - 1\right] \tag{2.8}$$

Using the concept of superposition, Ramey (1959) derived the following expression for the heat remaining in the reservoir as a function of time under a series of varying but discrete, heat injection rates.

$$Q(t) = \left(\frac{M_R}{M_s}\right)^2 \frac{h_t^2}{4\alpha_s} \sum_{j=1}^{n} U(t-t_j) \cdot \Delta\dot{Q}_j \left[e^{t_D - t_{Dj}} \, erfc \sqrt{t_D - t_{Dj}} + 2\sqrt{\frac{t_D - t_{Dj}}{\pi}} - 1\right] \tag{2.9}$$

Here, $\Delta\dot{Q}_j$ represents each step change in the rate of heat input, and $t_D - t_{Dj}$ is the dimensionless time since each change.

$$t_D - t_{Dj} = 4\left(\frac{M_s}{M_R}\right)^2 \frac{\alpha_s}{h_t^2}(t - t_j) \tag{2.10}$$

U is the unit function, defined as 1 when $t > t_j$ and 0 when $t < t_j$.

These are the two critical relationships of this model. Given a history of heat input rates, and the necessary reservoir and adjacent zone thermal properties, the amount of heat remaining in the reservoir at any time may be calculated. From this, the size of the steam zone is derived, and subsequently the amount of oil displaced.

$$V_s = \frac{Q(t)}{M_R \Delta T_i} \tag{2.11}$$

$$N_p = \varphi \frac{h_n}{h_t} \Delta S_o E_c V_s \tag{2.12}$$

ΔS_o is the change in oil saturation in the steam zone, and E_c is an efficiency factor relating the amount of oil displaced from the steam zone to that actually produced. These are the two unknowns that are later "adjusted" to fit the simplified model's to the field data. This relationship assumes no mobile gas in the reservoir at any time during the flood.

This model was incorporated into a computer program called Marx4.f, and is presented in Appendix A.

2.2.2 Voeel

Vogel's model assumes an instantaneous overlay at steam upon commencement of injection, followed by heat loss to the overlying and underlying zones. It also assumes that steam zone growth vertically downward proceeds slowly enough to allow application of the solution for heat loss for an infinite stationary plane. Figure 2.2, reprinted from Vogel (1983), is a schematic of this process.

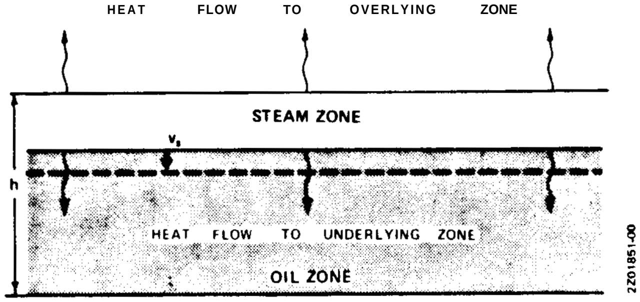

Fig. 2.2 Overlay Steamflood Model

The temperature distribution in either direction of heat loss for this situation may be described by

$$\frac{\partial^2 T}{\partial z^2} = \frac{1}{\alpha}\frac{\partial T}{\partial t} \tag{2.13}$$

with boundary conditions

$$T = T_s \quad \text{ut} \quad z = 0 \tag{2.14}$$

$$T = T_f \quad \text{at} \quad z > 0 \quad \text{for}\ t = 0 \tag{2.15}$$

T_s is the steam zone temperature and T_f is the ambient reservoir temperature.

The solution to this equation is

$$T(z,t) = T_f + (T_s - T_f)\, erfc\ \frac{z}{2\sqrt{\alpha t}} \tag{2.16}$$

Heat **flux** (heat loss per unit time per unit area) at either interface can then be found by the definition

$$f_z = -K\frac{\partial T}{\partial z} \tag{2.17}$$

evaluated at $z = 0$. Solving for the derivative at $z = 0$ yields

$$\left(\frac{\partial T}{\partial z}\right)_{z=0} = -\frac{\Delta T_i}{\sqrt{\pi\alpha t}} \tag{2.18}$$

where

$$\Delta T_i = T_s - T_f \tag{2.19}$$

Substituting back into Eq. (2.17) gives

$$f_z = \frac{\dot{Q}_l}{A} = \frac{K\Delta T}{\sqrt{\pi\alpha t}} \tag{2.20}$$

which is the equivalent of Vogel's (1983) **Eq.** (6).

To derive the cumulative heat loss, **Eq.** *(2.20)* is integrated over time. This gives

$$Q_l = 2KA\Delta T \sqrt{\frac{t}{\pi\alpha}} \tag{2.21}$$

which is identical to Vogel's (1983) **Eq.** (2).

From this point, Vogel proceeds to define the total heat injected into the ground as the sum of that remaining in the steam chest with that lost to overlying and underlying zones. Mathematically, this is

$$Q_t = AhM_R\Delta T_i + 2K_1A\Delta T_i \sqrt{\frac{t}{\pi\alpha}} + 2K_2A\Delta T_i \sqrt{\frac{t}{\pi\alpha_2}} \tag{2.22}$$

where the first term in the right-hand side, $AhM_R\Delta T_i$, is the heat retained by the steam chest. Assuming identical thermal properties for the overburden and underburden, he then solves for the heat efficiency as the fraction of heat injected that remains in the steam chest, Q_s / Q_t.

$$\frac{Q_s}{Q_t} = E_h = \frac{AhM_R\Delta T_i}{AhM_R\Delta T_i + 4K_sA\Delta T_i \sqrt{\frac{t}{\pi\alpha_s}}} \tag{2.23}$$

This may be reduced to

$$E_h = \frac{1}{1 + \frac{4K_s}{h}M_R} \sqrt{\frac{t}{\pi\alpha_s}} \tag{2.24}$$

At this point, however, Vogel substitutes Prats' (1969) dimensionless time function into the equation to arrive as

$$E_h = \frac{1}{1 + \sqrt{\frac{4}{\pi}\theta^2 t}} \tag{2.25}$$

with

$$\theta = \frac{2K_s}{M_R h \sqrt{\alpha_s}} \tag{2.26}$$

This seemingly simple identity, which Vogel uses to plot an efficiency curve very similar to that of Marx and Langenheim, is flawed by an ambiguous definition of h, the height parameter. Prats defines h as total pay zone height, in reasonable compliance with his piston-like frontal displacement model. Vogel's h, however, describes the vertical height of a constantly descending steam zone. Hence, his use of an h defined as total thickness, coupled with an instantaneous overlay of steam, leads to a steam chest equivalent in size to the entire reservoir. This clearly could not have been his intention in deriving his efficiency relationship.

Equation **(2.22)** was used as the basis of the model tested in this study. Rearranging the equation yields

$$AhM_R\Delta T_i = Q_t - 2K_1 A\Delta T_i \sqrt{\frac{t}{\pi\alpha_1}} \tag{2.27}$$

Q_t is cumulative heat injected through any given time, a known quantity dependent only on injection history. The two heat loss terms also involve only known parameters. A modification was made to account for variable steam injection temperatures (a topic to be discussed further in later sections) by superposition. In a manner exactly analogous to Ramey's method for Marx and Langenheim, the following equation was arrived at.

$$AhM_R\Delta T_i = Q_i - \left[\left(\frac{2K_1 A}{\sqrt{\pi\alpha_1}} + \frac{2K_2 A}{\sqrt{\pi\alpha_2}}\right) \cdot \sum_{j=1}^{n} U(t - t_j)\Delta(\Delta T_i)_j \sqrt{t - t_j}\right. \tag{2.28}$$

$\Delta(\Delta T_i)_j$ represents a step change in the difference between the steam injection temperature and ambient reservoir temperatures.

The volume of the steam zone, Ah, may then be found, and subsequently, the displaced and produced oil. Vogel4.f, a computer program performing these calculations, is presented in Appendix B.

2.3 Methodology

A three-fold procedure was proposed for determination of the incremental oil produced from the test pattern due to the addition of the surfactant Suntech IV. First, an attempt was made using the two models described in the previous sections to match the steam injection and oil production history for the entire lease from the time PetroLewis took control of the property in June of 1982. This date was chosen because it was felt that prior to the PetroLewis takeover, production data was simply not accurate enough to warrant a match attempt. Injection history prior to this time was input, however, since the accuracy of this data was considered acceptable. Next, the efficiency factor, E_c (originally input as 100%) was varied in order to facilitate the best possible match of historical data with our model results. With this accomplished, the final phase became that of predicting production from the test pattern based on the same efficiency factor utilized for the overall lease match. It was hoped that in this case, the model would predict somewhat lower oil production than actually occurred. The difference, it was hypothesized, would represent the incremental oil production due to the surfactant. Before turning to the results of this endeavor, however, it would be beneficial to discuss some of the details that had to be ironed out prior to the running of the models.

2.3.1 Superposition in Space

It was decided to treat the McManus lease as a group of six separate but superimposible units. The grouping of wells in each unit was based upon the date of commencement of steam injection for each well. In other words, all wells which began injection at the same time were grouped as a single unit. Since production wells experienced intermittent periods of cyclic steam injection during the life of the flood, it was necessary to include these wells into the various groups as well. This was again done according to first injection date. Each cyclic well went along with the adjacent group that had the closest first injection date. The resultant breakup of the lease, along with the appropriate dates of injection startup, is shown in Fig. 2.3.

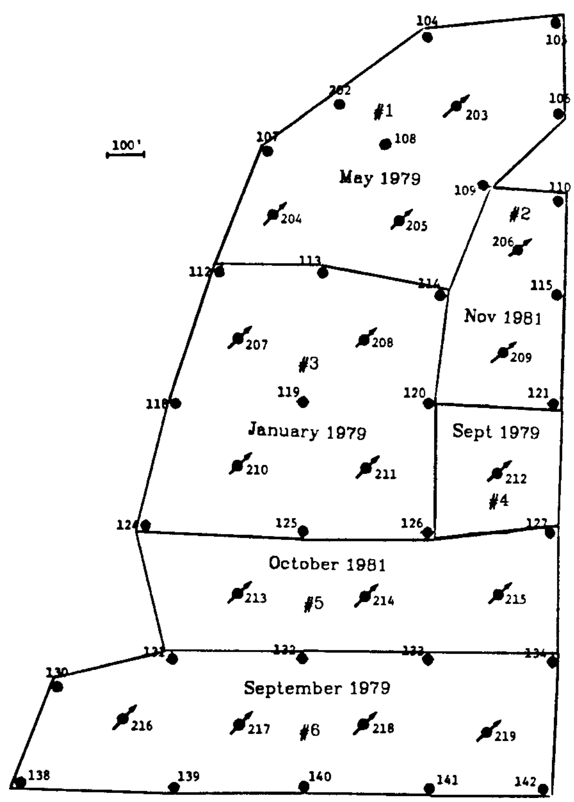

Fig. 2.3 Superimposible Well Groupings on Lease

Steam injection data, in the form of barrels of water equivalent per month, was gathered for each injector and summed across all wells in each group. These month-by-month average injection rates served as the basic input parameters for the two models tested. The model results for each well grouping were then added to provide the overall lease oil production prediction. An additional point that should be made concerns the use of cyclic steam injection data as an input to a steam flood model. Steam flooding is a continuous process, involving simultaneous injection and production, while cyclic injection usually involves a time lag between injection and production. As a result, it was decided that the cyclic injection data should be lagged by a certain amount of time in order to mimic the steam flood process. One, two and three months lag periods were chosen for this purpose. At first glance these lag periods appear to be quite short, but they are reasonable for the McManus lease since the history of the lease showed that cyclic steaming stimulation was short-lived. Tables of monthly injection data on a well-to-well basis are given in Appendix D.

Test pattern injection data was handled in an identical manner. Group boundaries were drawn exactly as before, except now only those injection and production wells which contributed to the test pattern were included in the respective groups. In addition, only that fraction of the injected steam which (in theory) directly flowed into the test pattern was included. Thus, the flow from injection well 208, located directly in the center of the five spot, was counted 100%, while those wells to the side (205, 207, 209, and 211) were counted 50% and those wells on the corners (204, 206, 210, and 212) were counted only 25%. This is shown schematically in Fig. 2.4.

2.3.2 Downhole Heat Calculations

In order to determine the true rate of heat injection at the sandface, it was necessary to calculate the heat losses incurred by the injected steam in the wellbore. As mentioned previously, the tool used for this calculation was a two-phase flow, wellbore heat loss computer program called Osman.f. This program is interactive, requesting from the user such data as tubing and casing specifications, thermal properties of the reservoir, injection rates and pressures, steam quality, etc. Whereas most of these data items could be safely estimated as uniform values across both space and time, certain values varied widely. Specifically, injection rates and pressures ran as high as 10,000 lb_m/hr and 250 psig early in the life of the flood, to 2500 lb_m/hr and 80 psig at the end of the flood. The first order of business, therefore, was reduction of this data in order to derive reasonable average input values for each of the well groupings.

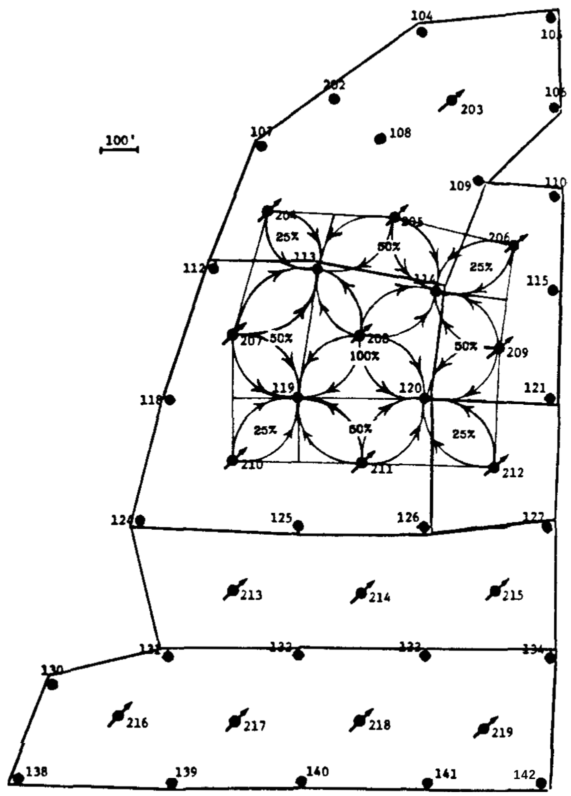

Fig. 2.4 Flow Lines of Test Pattern Injectors

First, an assumption of identical enthalpy/mass at every wellhead for the life of the flood was made. Next, five separate categories of injection pressure-rate pairs were created: 80 psig-2500 lb, /hr, 115 psig-1500 lb_m/hr, 150 psig-

6000 lb_m/hr, 200 psig-7000 lb_m/hr, and 250 psig-10,000 lb_m/hr. By assuming that the first category corresponded to a 75% steam quality at the wellhead, the wellhead steam quality corresponding to each of the other four categories was easily determined. This calculation is demonstrated in Appendix E. The final step was to utilize each of the category parameters as input for Osman.f, and determine the percentage of heat loss experienced by each in the wellbore. In addition, a series of times ranging from 1 month of injection to 6 years of injection were tested to determine how sensitive heat loss was to this variable. The relevant assumptions and inputs for these calculations are also given in Appendix E, and the final results are presented in Table 2.1.

TABLE 2.1
DOWNHOLE HEAT CONTENT AND TEMPERATURE CATEGORIES

Category Code	Injection Rate and Pressure	Heat Loss Range Over Time	Downhole Heat Content and Temperature
1	2500 lb, /hr 95 psia	3.27-4.02%	890 Btu/lb_m 316°F
2	5000 lb, /hr 130 psia	1.77%-2.19%	906 Btu/lb_m 321°F
3	6000 lb_m/hr 165 psia	1.91%-2.37%	905 Btu/lb_m 346°F
4	7000 lb_m/hr 215 psia	1.56%-1.95%	909 Btu/lb_m 372°F
5	10,000 lb, /hr 265 psia	1.17%-1.46%	912 Btu/lb_m 382°F

The way these results were used is as follows. Each injection well in every group was classified on a month-to-month basis as one of the five categories. Each group was then approximately averaged into a single category for any given month. The categories were incorporated into both computer models as heat content per mass of steam, and downhole steam temperatures. When entering month-by-month injection rates, a code was included that would trigger the correct heat content and downhole temperature for that month. A table listing the category code for each well grouping on a month-to-month basis may be found in Appendix E as well.

This type of arrangement, in which downhole temperature can change on a month-to-month basis, can lead to some problems. Generally, steam zone volume is determined on a cumulative basis. That is, the cumulative amount of heat remaining in the reservoir at the end of each month is calculated, then translated to a volume via division by $M_R \Delta T_i$. The problem, of course, is what ***AT,*** to use when it is not a constant over time. The solution used here was to determine steam zone volume on an incremental basis instead. The change in the heat content of the reservoir over each month was calculated by subtraction. This incremental heat gain was then translated into an incremental volume by use of the applicable downhole steam temperature for that month. Also, when low (or zero) steam injection rates led to a shrinking steam zone, oil production for that month was set to zero and not allowed to increase until through injection the steam zone was subsequently re-established to its previous size.

2.3.3 Reservoir Properties-Nonthermal

Non-thermal reservoir properties of the McManus Lease were derived from two sources. One was the Second Annual Report for the pilot, entitled **A** *field Experiment of Steam Drive with In-Situ Foaming* ***(1982)*** and the other was a GeothermEx report entitled, *Preliminary Geological Model of the McManus Lease–Kern River Field-- Bakersfield, California* ***(1981)*** All necessary parameters, with the exception of net and gross thickness, are listed in Table **2.2.** Note that no attempt was made to define different sets of values for each well grouping. Instead, uniform values for the entire lease were used. There simply was not enough information available to do otherwise.

TABLE 2.2
SELECTED RESERVOIR PROPERTIES.

Porosity	25%
Initial oil saturation	50%
Final oil saturation	10%
Oil formation volume factor	1.0
Ambient temperature	75°F
Percentage heat produced	0

Net and gross reservoir thicknesses are critical parameters for the Marx-Langenheim model. Thus, an attempt was made to define them as accurately as possible for each well grouping. The above mentioned GeothermEx report contained geological cross-sections of selected wells on the McManus Lease. In general, four zones, separated by impermeable (or semipermeable) layers, could be identified. Net and gross thickness of these layers were recorded, arranged according to well grouping, and arithmetically averaged to arrive at a single value per grouping. This calculation was performed under three different, scenarios. Under the assumption that gravity override forced injected steam directly to the top of the formation, the first calculation involved only the uppermost layer of each cross-section. The second involved the two top layers, to account for the possibility of the combined effect of gravity override and a highly permeable ***thief*** zone. Finally, as a control, complete four layer net and gross thicknesses were calculated and recorded. These results are presented in Table **2.3,** and the raw data utilized for the calculations are shown in Appendix F.

The important parameters of the Vogel model were not thicknesses themselves, but rather the ratio of net to gross thickness. Since this number was not nearly as variable as thickness, it was unnecessary to account for different scenarios. The net to gross thickness ratio of the complete four layer thickness

TABLE 2.3
THICKNESS AND AREA SCENARIOS FOR EACH WELL GROUPING

Well Groupings	All Four Layers		Top Two Layers		Top Layer		
	Net Thickness (ft)	Gross Thickness (ft)	Net Thickness (ft)	Gross Thickness (ft)	Net Thickness (ft)	Gross Thickness (ft)	Areal Extent (Acres)
Total Lease							
#1	307	356	137	151	07	71	9
#2	299	348	147	159	71	75	4.5
t3	252	312	131	155	72	79	9
64	220	321	144	164	85	95	2.25
#5	235	299	126	137	65	71	6.75
#6	245	305	126	157	59	64	9
Entire Lease	260	324					40.5
Test Pattern							
#1	295	351	127	147	68	75	1.09
#2	2Q4	348	144	158	75	81	1.69
t3	250	310	128	156	67	75	5.06
64	265	335	148	166	84	94	0.56
Entire Lease	276	336					9

was therefore chosen as the relevant input value for this model. These figures, along with the surface area for each well grouping, are also listed in Table 2.3.

2.3.4 Reservoir Properties-Thermal

Volumetric heat capacity, thermal conductivity, and thermal diffusivity were the three parameters of interest. In order to determine them, an assumption regarding the geological structure of the reservoir and the temperatures and saturation conditions therein had to be made.

The McManus Lease section of the Kern River field is a sand-silt reservoir. It was decided, therefore, to first determine the thermal properties of the sand and silt layers individually, and then combine them in the proper proportion to reflect the net to gross thickness ratios. Various conditions of temperature and saturation may exist at any given time during a flood. The following scenarios were chosen for use in this evaluation.

(1) A steam zone that consisted mostly of sand, with some silt, at an elevated temperature. This elevated temperature was intermediate between ambient reservoir temperature (75°F) and average sandface steam injection temperature (350°F). The pore space of the sand was occupied by residual oil, with the remainder divided equally between steam and water. Silt in the steam zone was assumed to contain 100% water at the intermediate temperature.

(2) An overburden and underburden that existed at ambient temperature. For the case in which the the entire thickness of the formation was used as the height parameter, these adjacent zones were presumed to lie outside any oil-bearing formation, and therefore consisted of sand and silt that were 100% saturated with water. For the case in which part of the underburden lay within the oil-bearing formation (such as

the Vogel Model or the Marx-Langenheim model with upper layer thicknesses used as the height parameter), the make-up was assumed to be sand that was saturated with both water and oil, and silt saturated only with water.

Volumetric heat capacity was evaluated using the following formula of Prats (1982).

$$M_R = M_\infty(1-\varphi) + M_o \varphi S_{or} + M_w \varphi S_{wr} + \varphi S_{st} \left[\frac{\rho_{st} L_v}{\Delta T_i} + \rho_{st}\, C_w \right] \tag{2.29}$$

where

$$M = \rho C \tag{2.30}$$

C, which is heat capacity was determined for oil with Gambill's (1957) empirical relationship

$$C_o = \frac{0.388 + 0.00045 T}{\sqrt{\gamma_o}} \tag{2.31}$$

Rock matrix heat capacity came from Somerton and Boozer's (1960) empirical curves.

Somerton, *et al.* (1973) proposed empirical relationships for determining thermal conductivity of unconsolidated formations. For quartzitic sands,

$$\lambda = 4.45 f_q + 2.65\,(1 - f_q) \tag{2.32}$$

with f_q equal to the fractional volume of quartz in the sand. The thermal conductivity, of the reservoir at 125°F was obtained from

$$\lambda_R = 0.735 - 1.30\varphi + 0.390\, \lambda_m \sqrt{S_w} \tag{2.33}$$

with temperature correction from

$$\lambda_R(T) = \lambda_R - 1.28 \times 10^{-3}(T - 125)(\lambda_R - 0.82) \qquad (2.34)$$

After obtaining thermal conductivity thermal diffusivity followed from

$$\alpha = \frac{\lambda}{M} \qquad (2.35)$$

The resulting thermal properties of sand and silt under the various scenarios is shown in Table 2.4. Calculations for these results can be found in Appendix D.

TABLE 2.4
THERMAL PROPERTIES OF SAND AND SILT LAYERS IN RESERVOIR AND ADJACENT ZONES

Material	Scenario	M (Btu/ft^3 °F)	a (ft^2/Day)	K (Btu/ft-hr-°F)
Sand	In steam zone	34.95	N/A	N/A
Silt	In steam zone	43.58	N/A	N/A
Sand	In overburden or underburden, saturated with water only	40.40	0.980	1.65
Sand	In overburden or underburden, saturated with initial oil and water at initial conditions	35.88	0.855	1.28
Silt	In overburden or underburden, saturated with water only	41.87	0.906	1.58

The final step in this procedure was to properly proportion sand and silt properties for the individual well groupings. For the steam zone, this entailed merely taking a weighted average of sand and silt properties using net to gross thicknesses as the weighting factors. Overburden and underburden calculations were slightly more complicated. In the Marx and Langenheim model, overburden and underburden properties were assumed identical. For the control scenario in which the entire thickness of the reservoir was input, the overburden and underburden were both assumed to be comprised of 50% silt with no oil saturation and 50% sand with no oil saturation. Average values were calculated accordingly. For the cases in which only the top one or two layers were considered, the overburden was again assumed to be half sand and half silt with no oil saturation. This time, however, the underburden, being partially within the oil-bearing formation, was taken to be comprised of sand containing both oil and water, and silt containing only water, in equal proportions. Thus, underburden and overburden properties were evaluated separately, then averaged to obtain a single figure. The thermal properties for the Marx and Langenheim model are given in Table 2.5.

For Vogel's model, steam zone properties were calculated in an identical fashion. The overburden and underburden calculations were similar to those of a upper layer scenario, but did not require the final averaging step. This was due to the fact that, unlike the Marx and Langenheim model, Vogel's model allows for differing overburden and underburden properties. Table 2.6 presents the results of these calculations.

2.4 Results and Discussion

As mentioned previously, two analytical steamflood models were tested in this evaluation. These were Marx and Langenheim's frontal displacement model (with Ramey's modification for variable injection rates) and Vogel's overlay model. The results of each of these attempts are discussed next in the following sections.

TABLE 2.5
THERMAL PROPERTIES OF WELL GROUPINGS—MARX AND LANGENHEIM MODEL

Well Grouping	All Four Layers			Top Two Layers			Top Layer		
	M_R	M_S	α_s	M_R	h_s	α_s	M_R	h_s	α_s
	(Btu/ft^3 °F)	(Btu/ft^3 °F)	(ft^2/Day)	(Btu/ft^3 °F)	(Btu/ft^3 °F)	(ft^2/Day)	(Btu/ft^3 °F)	(Btu/ft^3 °F)	(ft^2/Day)
Total Lease									
#1	36	41	0.943	36	39	0.861	35	39	0.861
#2	36	41	0.843	98	39	0.861	35	39	0.881
#3	37	41	0.943	36	39	0.681	36	39	0.681
#4	36	41	0.843	36	39	0.881	36	39	0.861
#5	36	41	0.943	37	39	0.861	36	39	0.661
#6	36	41	0.943	37	39	0.881	36	39	0.88
Teat Pattern									
#1	36	41	0.943	36	39	0.861	36	39	0.861
#2	36	41	0.s43	36	39	0.861	36	39	0.861
#3	37	41	0.943	36	39	0.881	36	39	0.881
#4	37	41	0.943	36	39	0.861	36	39	0.881

TABLE 2.6
THERMAL PROPERTIES OF WELL GROUPINGS—VOGEL MODEL

Total Lease	M_R (Btu/ft^3°F)	K_1 (Btu/ft-hr-°F)	K_2 (Btu/ft-hr-°F)	α_1 (ft^2/Day)	α_2 (ft^2/Day)
Well Grouping					
#1	37	1.44	1.33	0.942	0.864
#2	37	1.44	1.33	0.942	0.004
#3	37	1.44	1.33	0.942	0.067
#4	38	1.44	1.30	0.942	0.073
#5	37	1.44	1.33	0.942	0.060
#6	37	1.44	1.33	0.942	0.867
Entire Lease	37	1.44	1.33	0.942	
Test Pattern					
#1	37	1.44	1.33	0.942	0.065
#2	37	1.44	1.33	0.942	0.085
#3	37	1.44	1.33	0.942	0.867
#4	37	1.44	1.33	0.942	0.068
Entire Pattern	37	1.44	1.33	0.842	

2.4.1 *Marx* and Langenheim

Figures 2.5 through 2.13 summarize the results of the history match using the Marx and Langenheim stearnflood model. Nine separate cases were run, representing all three steam zone thickness scenarios (upper layer only, top two layers only, and total thickness) and all three cyclic steam lag scenarios (one, two, and three months). Each case produced a set of three graphs. The first matched historical cumulative production for the entire lease from June 1981 to October 1983 against predicted cumulative production during that span, and was based on an efficiency factor of 100%. Since no injection data was available for November and December, these two months were neglected. Figures 2.5a through 2.13a show these results. In each case, cumulative historical production to 6/81 was 299,561 barrels, while the model predicted cumulative production ranged from about 775,000 barrels to 985,000 barrels. The efficiency factor, derived as the quotient of historical cumulative production over predicted cumulative production, therefore ranged from 30.41% to 38.46% for the assorted cases.

The results using these adjusted efficiency factors are shown in Figs. 2.5b through 2.13b. Note the exact overlay of the initial point on each figure, verifying that the correct efficiency factor for matching cumulative production through 6/81 was used. In all cases, less production was predicted by the model than historically occurred. While the historical cumulative production for the lease through 10/83 was approximately 650,000 barrels, the model predicted a cumulative production ranging from 500,000 barrels to 565,000 barrels. This yields a percentage error ranging from 13% to 23%. On an incremental basis, 350,000 barrels of oil were actually produced between 6/81 and 10/83. The model prediction ranged from approximately 200,000 barrels to 265,000 barrels. This percentage error is considerably larger, ranging from 24% to 43%.

Finally, test comparisons were made using the identical derived efficiency factors. For these graphs, historical production was not inserted until June 1982, the date at which Chemical Oil Recovery Company took control of production reporting for the test pattern. As outlined by Brigham, *et al.* (1984) individual well production data prior to this time could not be considered reliable. Because of this lack of information, cumulative test pattern production data to this time had to be considered an unknown. Instead, we used the model's predicted cumulative production at 6/82 as the starting point of the historical curve. Hence, our test pattern match is not a true match in that it neglects cumulative production and simply compares production on an incremental basis. These results are shown in Figs. 2.5c through 2.13c. Once again, the model predicted less oil production in all cases than actually occurred. On an incremental basis (the only valid basis for comparison given the artificiality of the initial point) the model predicted oil production ranging from about 25,000 barrels to 39,000 barrels. True incremental production was approximately 55,000 barrels.

Several points regarding these results are notable.

(1) Table 2.7 lists the difference in final Cumulative production for all nine cases run, both on a total lease basis, and on a test pattern basis. In all cases, historical production exceeded the model prediction, just as had been hoped. Unfortunately, the magnitude of this excess for the total lease was far too large to be explained simply by the presence of the surfactant. Decline curve analysis in Brigham, *et al.* (1984) indicated a range of incremental oil due to the surfactant from 14,000 to 31,400 barrels. The model differences for the total lease ranged from about 85,000 barrels to

(a) Total Lease
100%Efficiency

(b) Total Lease
30.41% Efficiency

(c) Test Pattern
30.41% Efficiency

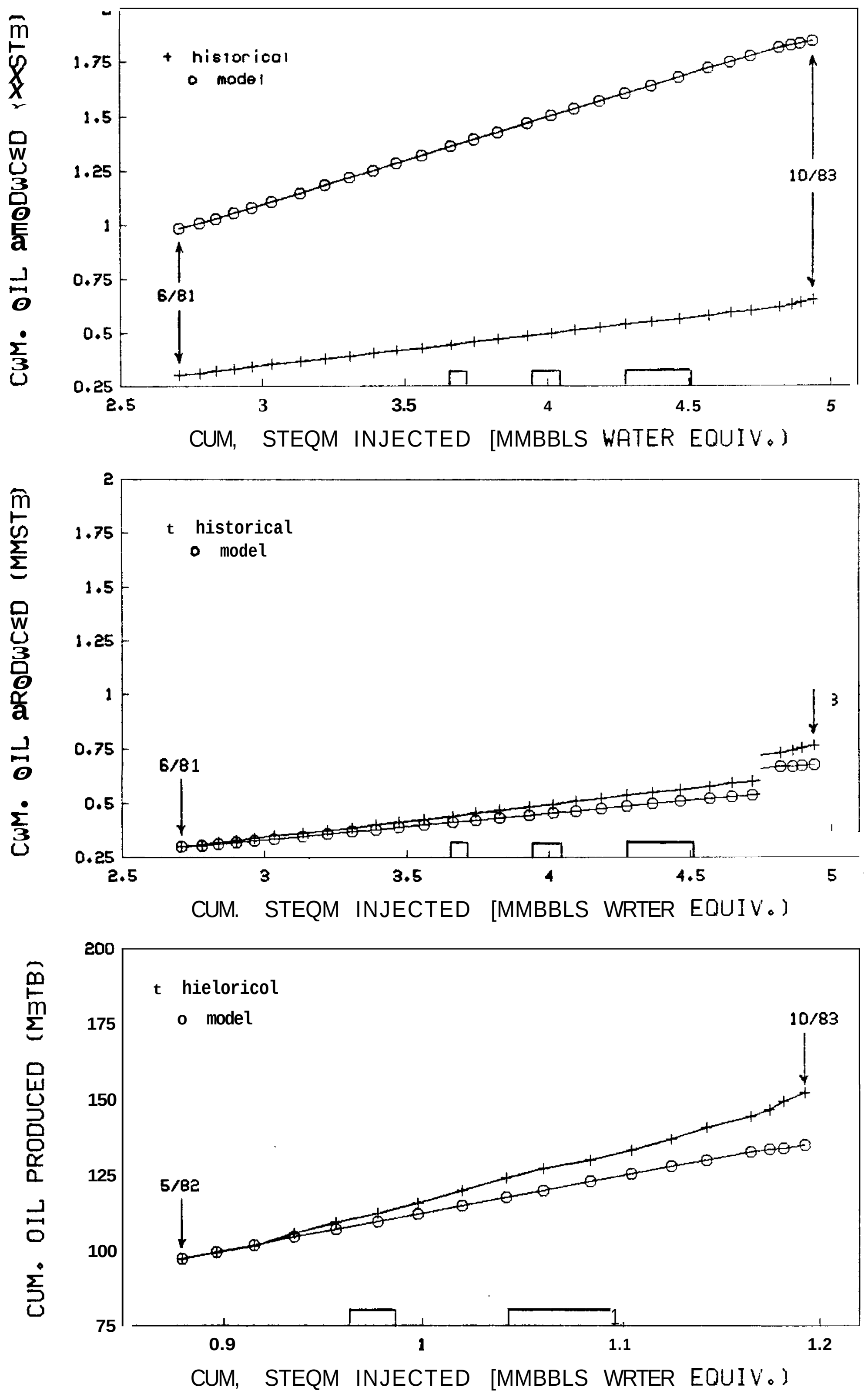

Fig. 2.5 Marx-Langenheim Model-1 Month Lag in Cyclic Injection and Total Formation Thickness

(a) Total Lease
100%Efficiency

(b) Total Lease
33.77%Efficiency

(c) Test Pattern
33.77%Efficiency

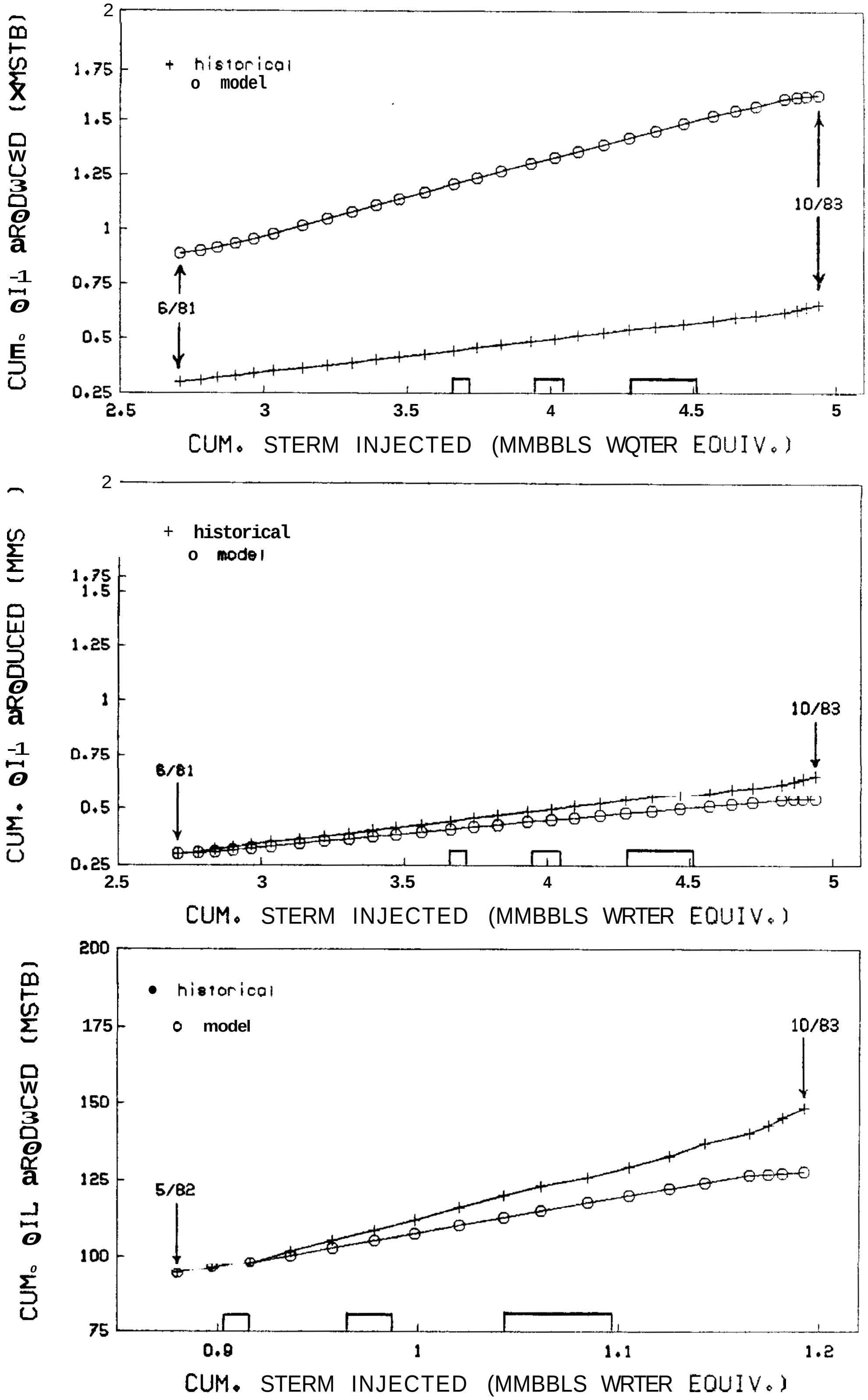

Fig. 2.6 Marx-Langenheim model–1 Month Lag in Cyclic Injection and Top Two Slices Only

(a) Total Lease
100%Efficiency

(b) Total Lease
38.60%Efficiency

(c) Test Pattern
38.60%Efficiency

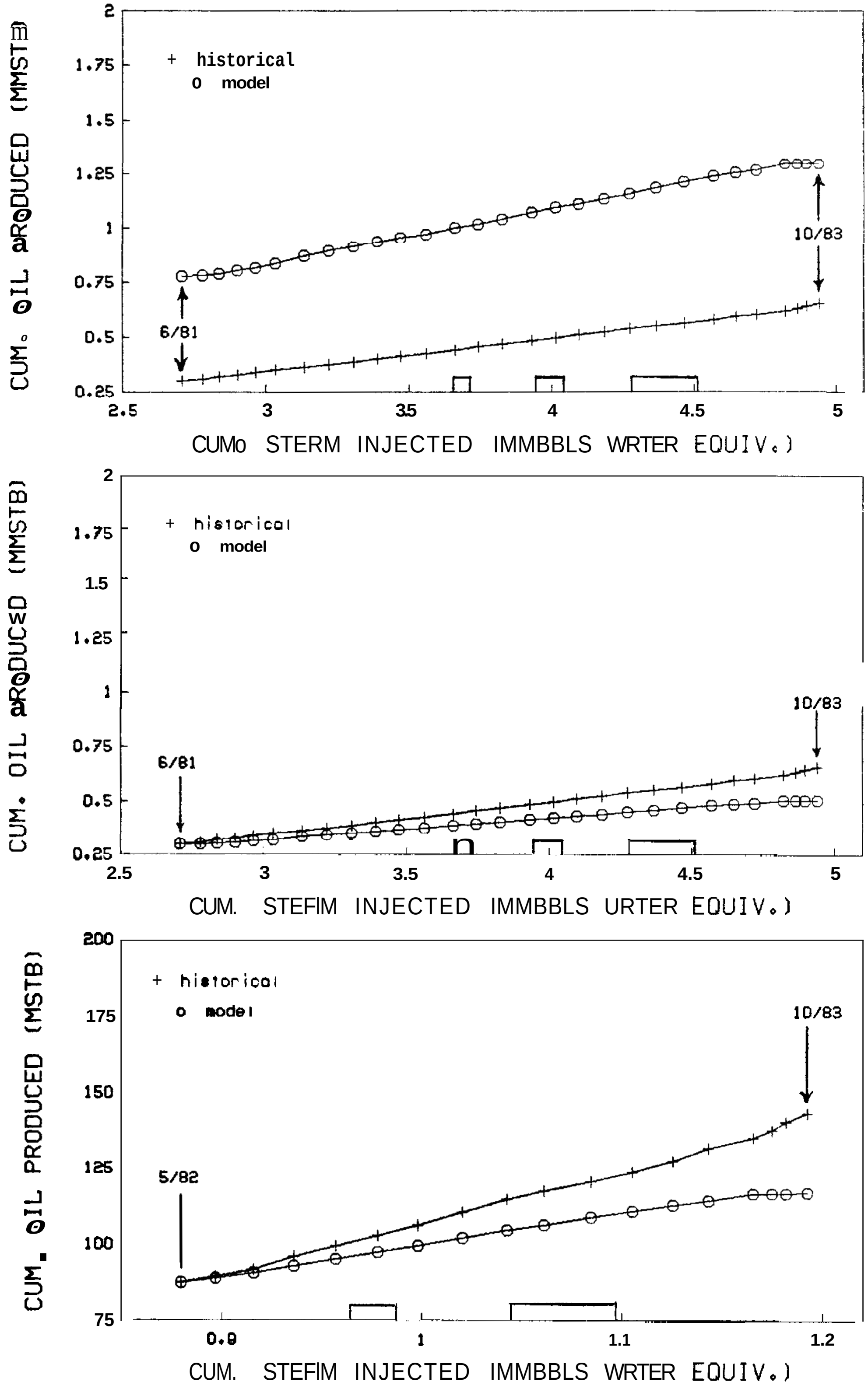

Fig. 2.7 Marx-Langenheim Model–1 Month Lag in Cyclic Injection and Top Slice Only

(a) Total Lease
100%Efficiency

(b) Total Lease
31.46%Efficiency

(c) Test Pattern
31.46%Efficiency

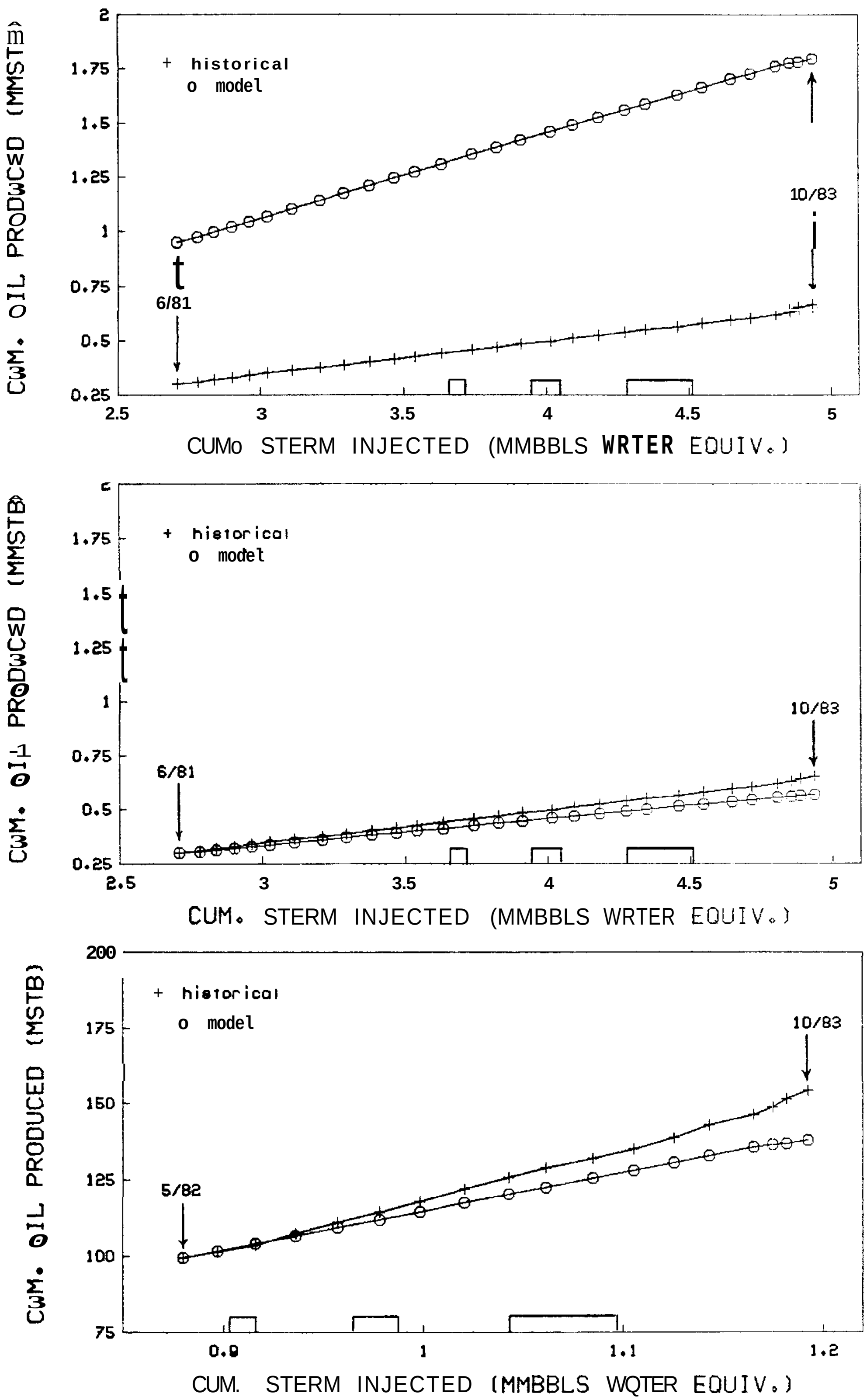

Fig. 2.8 Marx-Langenheim Model–2 Month Lag in Cyclic Injection and total Formation Thickness

(a) Total Lease
100%Efficiency

(b) Total Lease
33.72% Efficiency

(c) Test Pattern
33.72% Efficiency

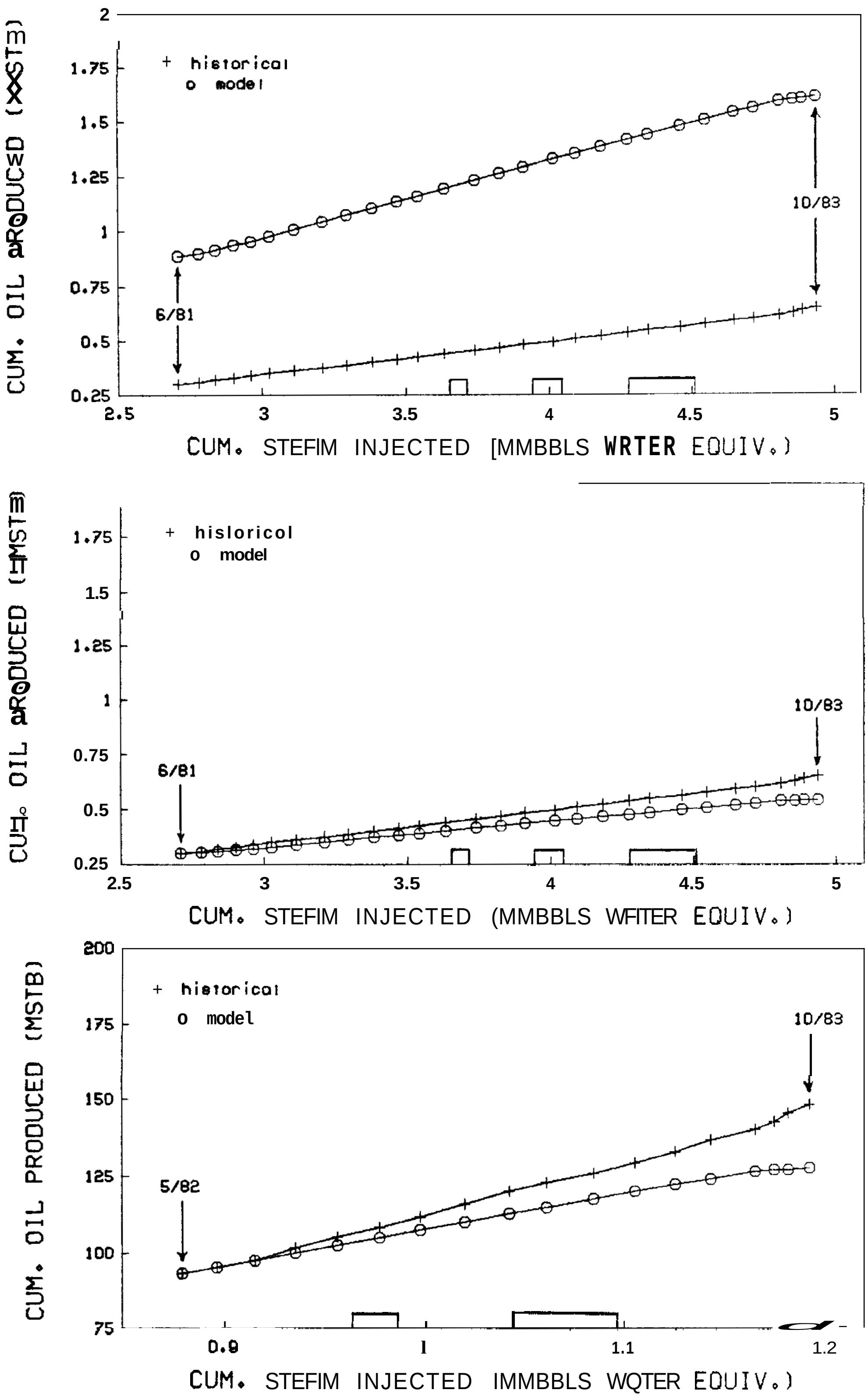

Fig. 2.9 Marx-Langenheim Model4 Month Lag in Cyclic Injection and Top Two Slices Only

(a) Total Lease
100%Efficiency

(b) Total Lease
38.46% Efficiency

(c) Test Pattern
38.46% Efficiency

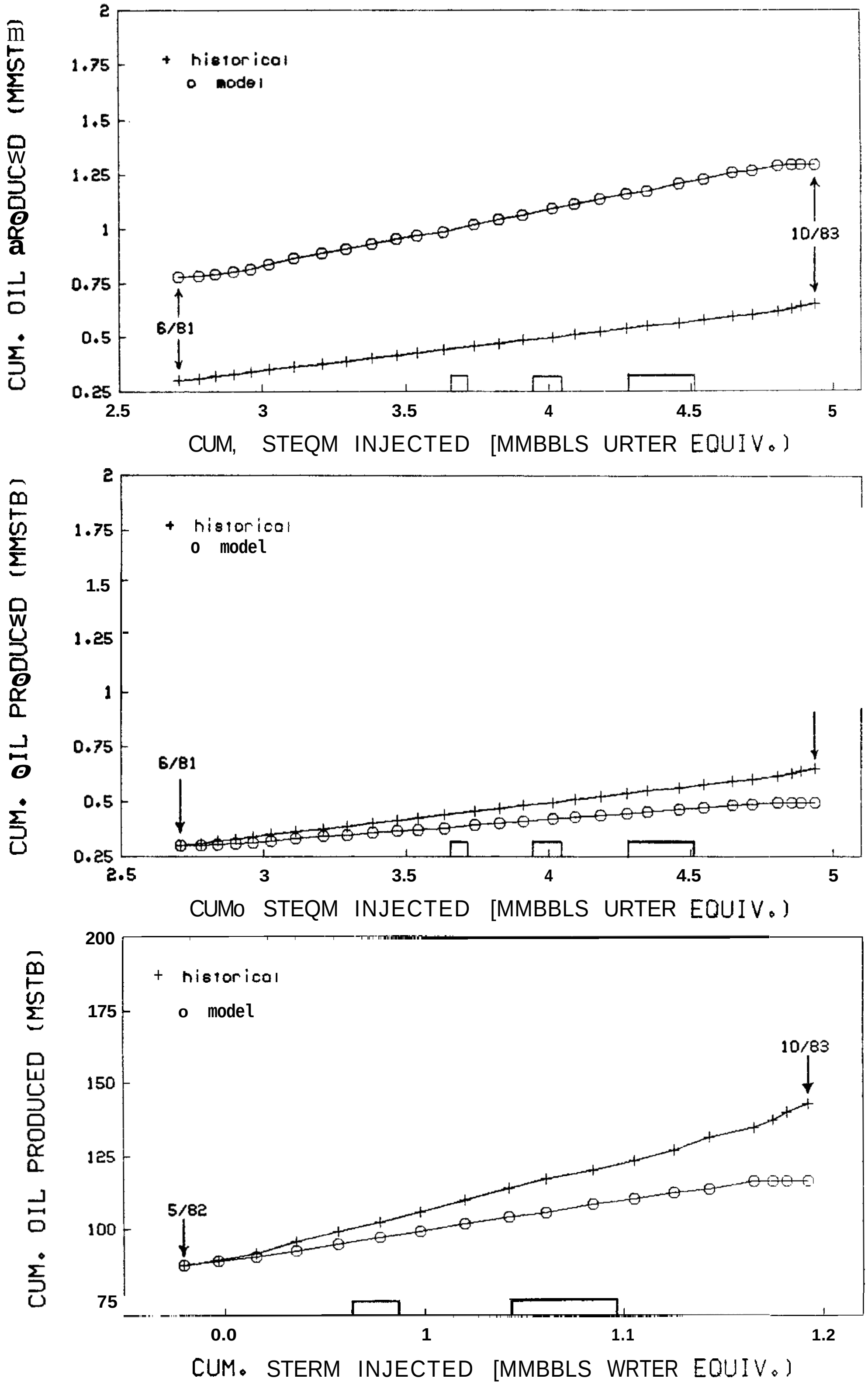

Fig. 2.10 Marx-Langenheim Model - 2 Month Lag In Cyclic Injection and Top Slice Only

(a) Total Lease
100%Efficiency

(b) Total Lease
30.41%Efficiency

(c) Test Pattern
30.41%Efficiency

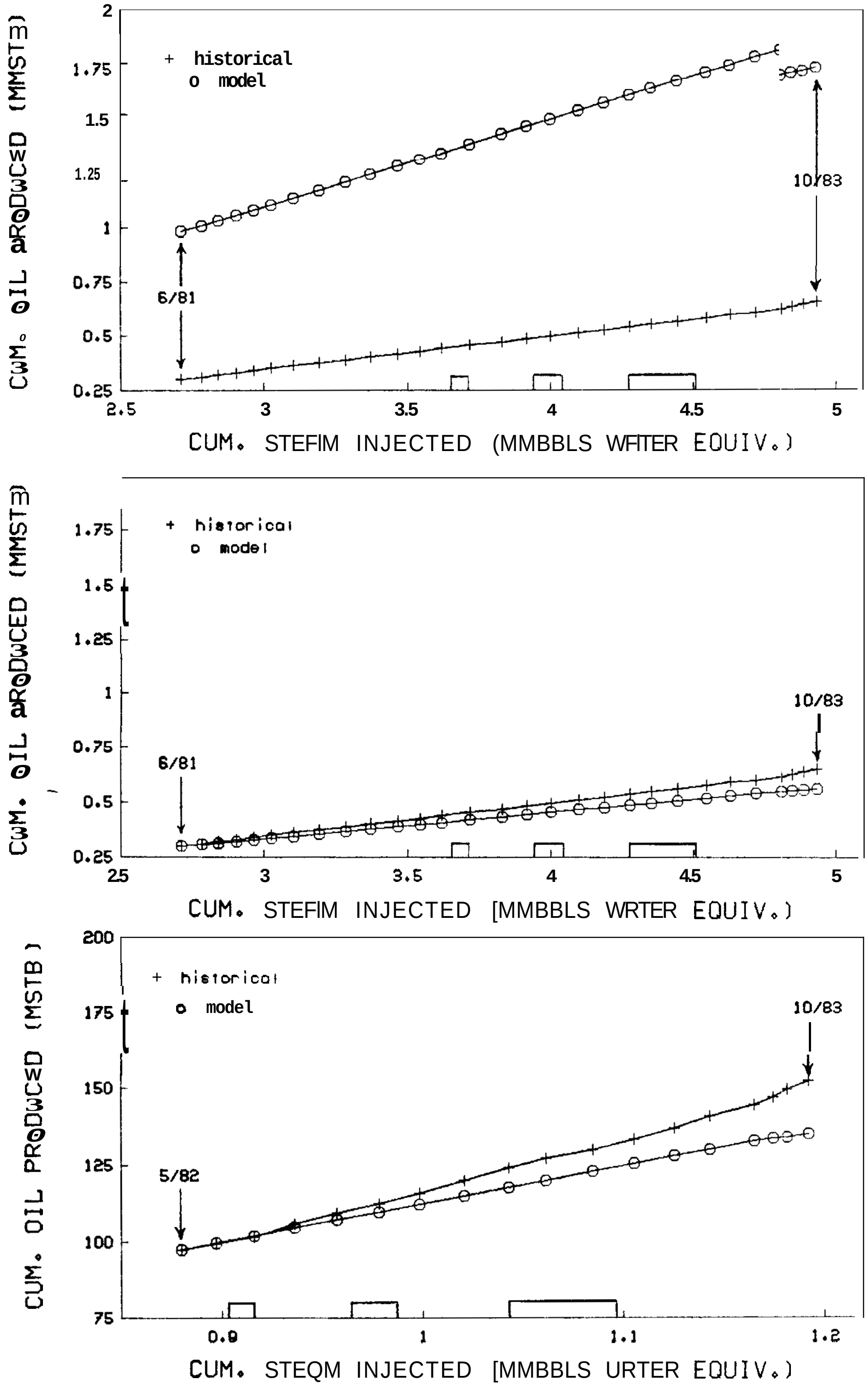

Fig. 2.11 Marx-Langenheim Model–3 Month Lag in Cyclic Injection and Total Formation Thickness

(a) Total Lease 100%Efficiency

(b) Total Lease 33.73% Efficiency

(c) Test Pattern 33.73%Efficiency

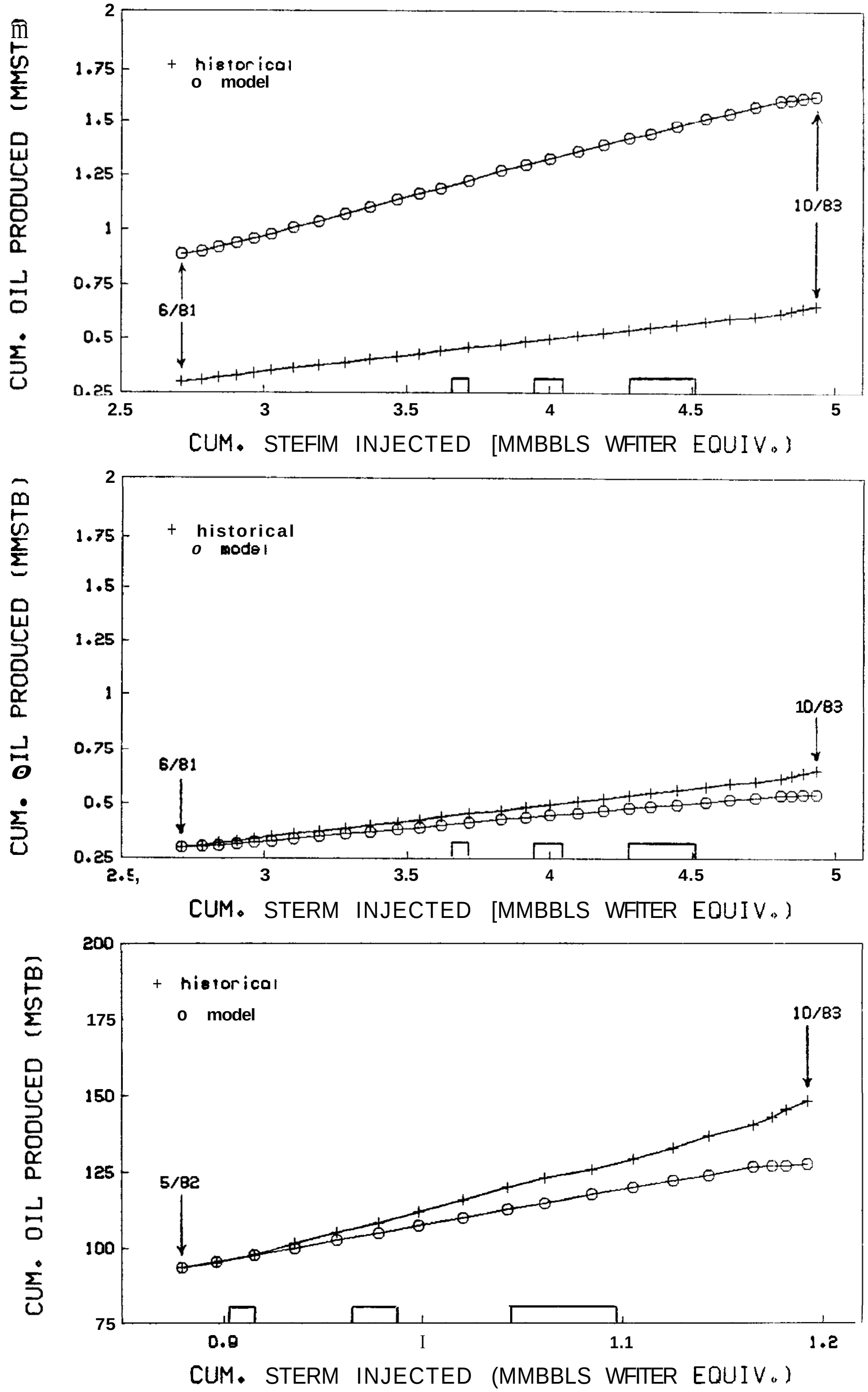

Fig. 2.12 Marx-Langenheim Model–3 Month Lag in Cyclic Injection and Top Two Slices Only

(a) Total Lease 100%Efficiency

(b) Total Lease 38.45%Efficiency

(c) Test Pattern **38.45%** Efficiency

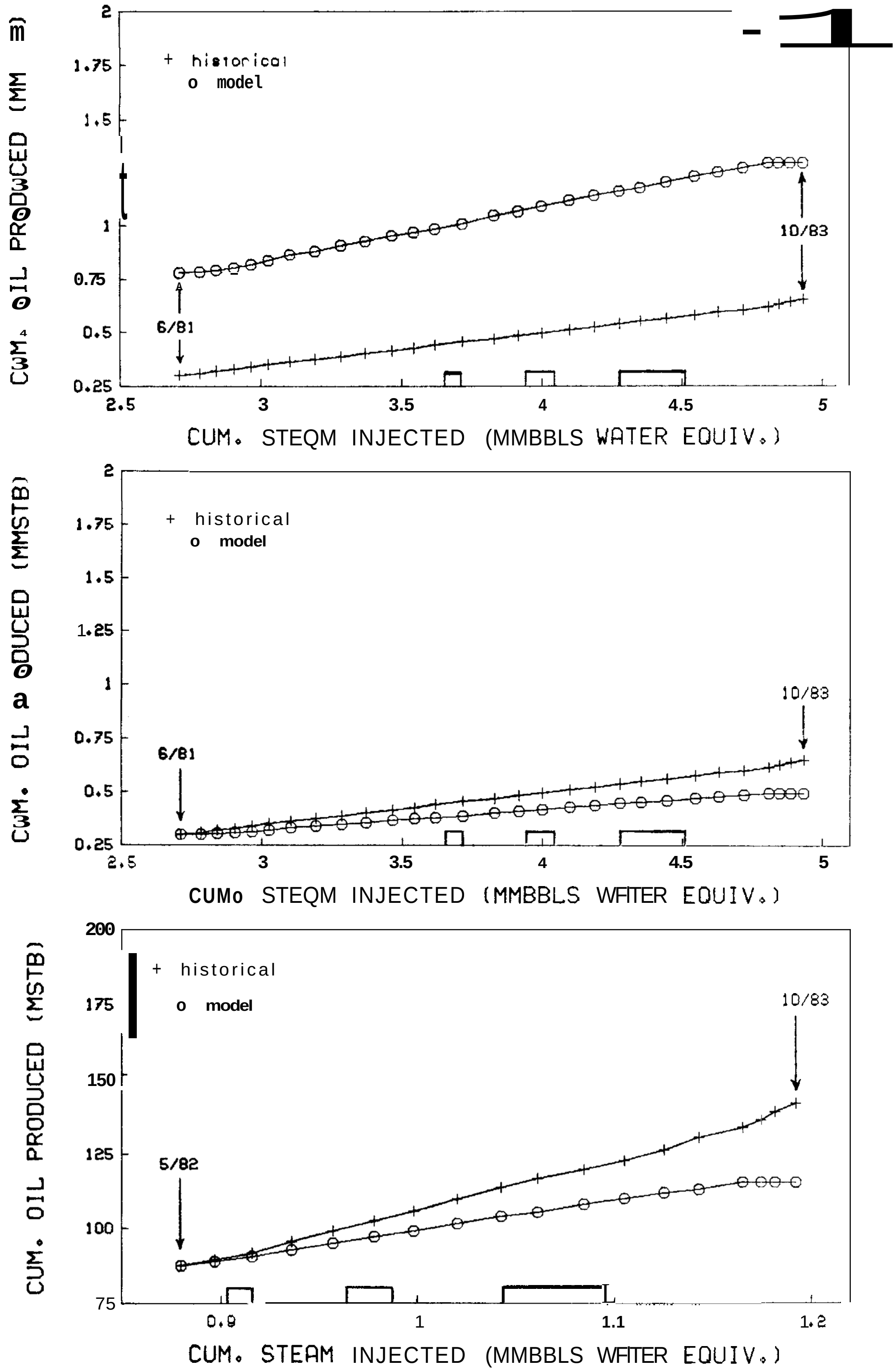

Fig. **2.13 Marx-Langenheim Model–3 Month** Lag **in Cyclic Injection and Top Slice Only**

TABLE 2.7
CUMULATIVE PRODUCTION DIFFERENCE BETWEEN HISTORICAL RESULTS AND MARX AND LANGENHEIM MODEL

	Total Lease (Bbls Oil)	Test Pattern (Bbls Oil)
1 Month Lag		
All slices	89,514	17,356
Top 2 slices	106,736	20,484
Top 1 slice	150,335	26,125
2 Month Lag		
All slices	04,773	16,411
Top 2 slices	107,302	20,539
Top 1 slice	153,306	26,234
3 Month Lag		
All slices	89,562	17,361
Top 2 slices	107,122	20,532
Top 1 slice	153,846	26,247

over 150,000 barrels.

(2) It is important to keep in mind that the total lease match results were not intended to be a yardstick for determining incremental production. Rather, they were simply a device for arriving at the correct match parameters with which to run the test pattern cases. In this context, a match which ranged in percent error from 13% to **23%** of total cumulative production could be considered reasonable, if not outstanding. In addition, it was felt that the parameter of percentage difference based on incremental production was not really a good indicator of match results. This figure was therefore ignored.

(3) While it is clear that the cyclic steam injection lag time made very little difference in the results, formation thickness scenario did. Surprisingly, the model matches improved as thickness increased. Given the hypothesis of gravity override and highly permeable ***thief*** zones driving steam to the top at the formation, this was unexpected.

(4) Finally, test pattern results showed remarkable consistency with the previously mentioned decline curve analyses, with final cumulative differences ranging from about 16,000 barrels to 30,000 barrels. In addition, examination of the test pattern graphs reveal that historical production began its upswing just as the first slug of surfactant was injected.

(5) In all of the test pattern graphs, the final few months of steam injection produced a sharp dropoff in predicted production rate. This reflects the model's reaction to the drastically decreased steam injection rate which occurred over these months. The

model, unlike real life, adjusts immediately, leading to a decline in production that very same month.

A second approach to the problem of matching historical and model results was suggested--one, it was hoped, which would establish a better lower limit for the incremental test pattern production. With this method, it was assumed that lease-wide cumulative production was an inaccurate figure, and for all practical purposes unknown. Hence, the modification in efficiency factor was performed not to match historical cumulative production through 6/81, but rather to match the historical slope after that time, ie. a production rate match. The net effect of this was to produce not a cumulative production match pre-6/81, but an incremental production match post-6/81. This type of methodology suggests that perhaps the Marx and Langenheim model more accurately depicts a steamflood in its later stages, after any early time instabilities have been overcome.

Figures 2.14 through 2.16 show the results of these efforts for both the total lease and the test pattern. Only the one month lag case is used here, as the insignificance of varying this parameter has already been established. Note that for the total lease cases, the historical and the model curves were not overlain; this was done to highlight the parallel nature of the two curves. The test pattern cases, shown in Figs. 2.14c through 2.16c, gave the expected results. Cumulative incremental oil produced for the three thickness scenarios were 8,448, 11,309, and 10,589 barrels of oil, all somewhat lower than the previous test pattern results. Thus, the lower limit of incremental oil production due to the surfactant was established as approximately 8,500 barrels, at least according to the Marx and Langenheim model.

Marx and Langenheim is strictly a frontal displacement model, and does not try to account for steam overlay. Improvement was attempted by incor-

(a) Total Lease
100% Efficiency

(b) Total Lease
37.68% Efficiency

(c) Test Pattern
37.68% Efficiency

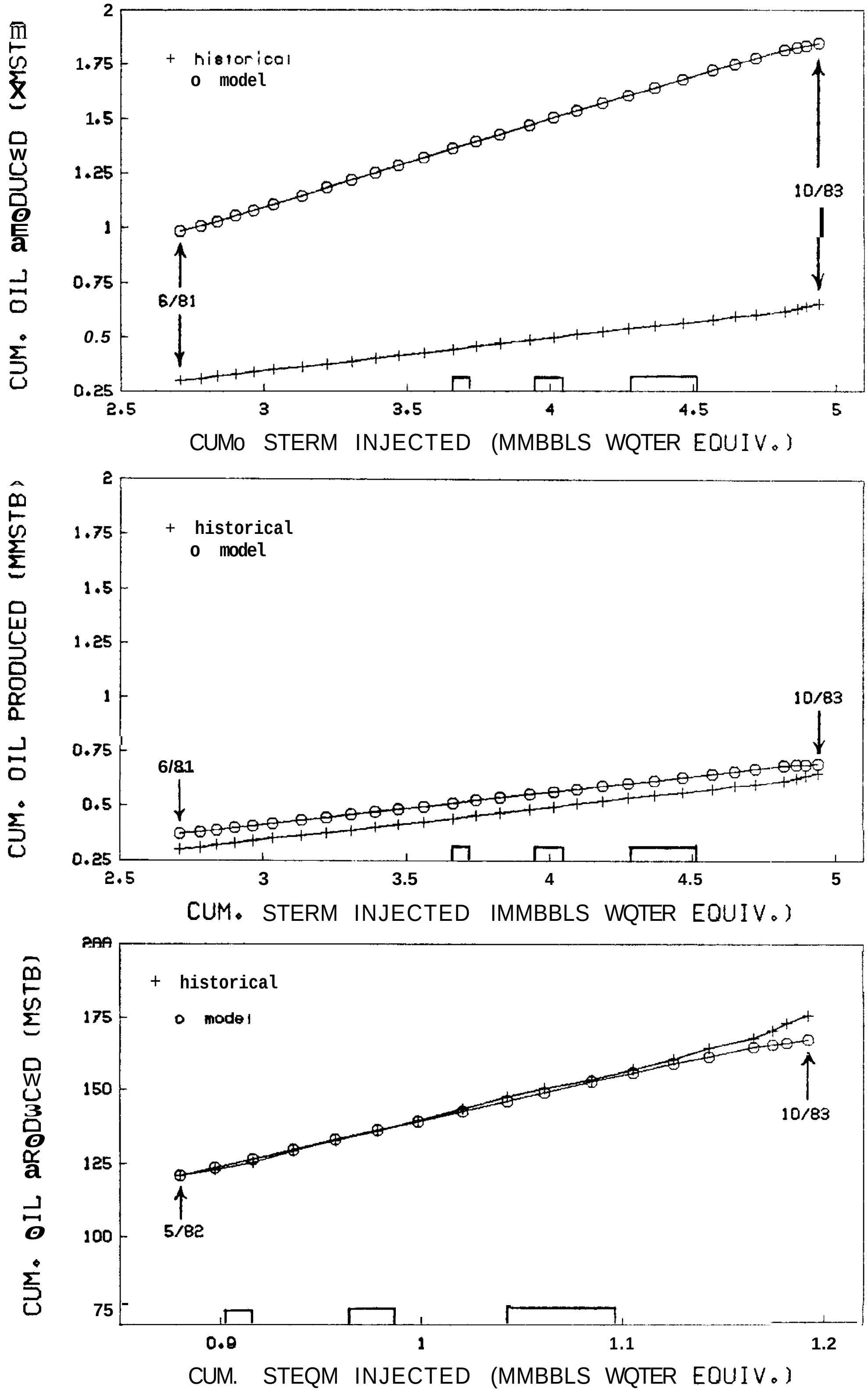

Fig. 2.14 Marx-Langenheim Model–1 Month Lag in Cyclic Injection and Total Formation Thickness–Reduced Efficiency for Incremental Production Match

(a) Total Lease
100% Efficiency

(b) Total Lease
43.56% Efficiency

(c) Test Pattern
43.56% Efficiency

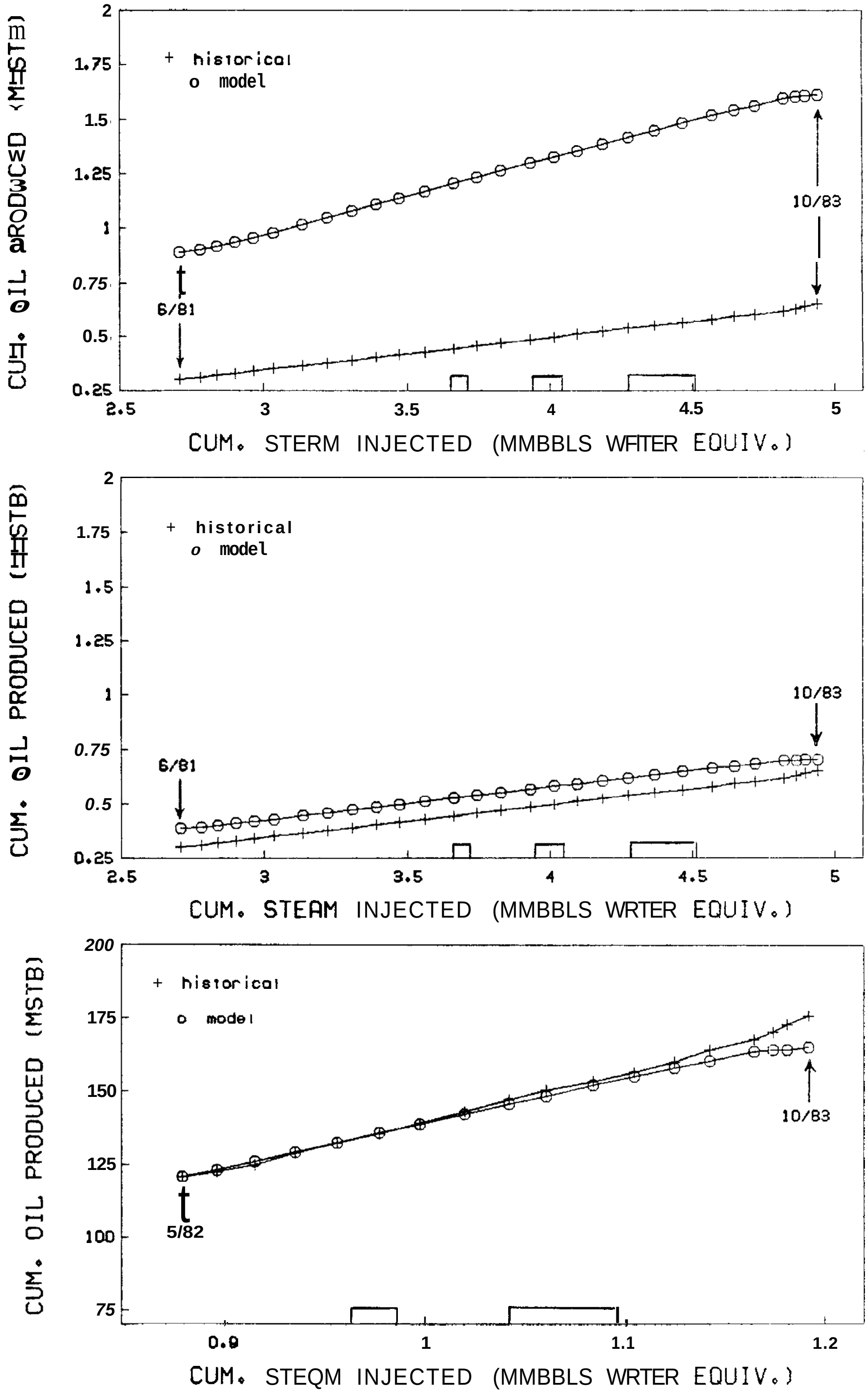

Fig. 2.15 Marx-Langenheim Model–1 Month Lag in Cyclic Injection and Top Two Slices Only–Reduced Efficiency for Incremental Production Match

(a) Total Lease
100%Efficiency

(b) Total Lease
58.21%Efficiency

(c) Test Pattern
58.21%Efficiency

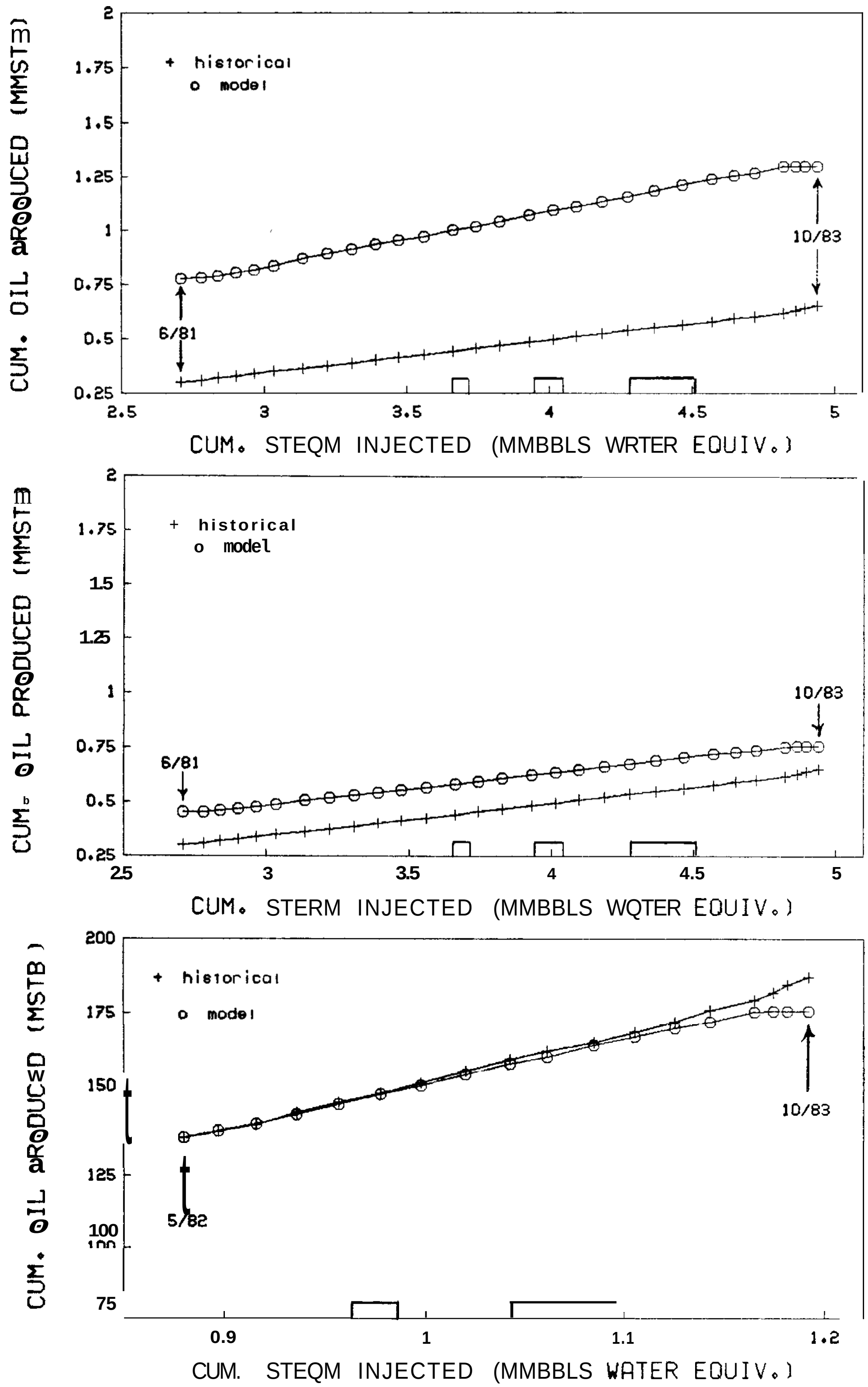

Fig. 2.16 Marx-Langenheim Model–1 Month Lag in Cyclic Injection and Top Slice Only–Reduced Efficiency for Incremental Production Match

porating different thickness scenarios into the model; this proved to be, at best, a guarded success. Some possible reasons, aside from the obvious one just mentioned, follow.

(1) The assumption of incremental steam zone growth based on the temperature of the steam injected that month implies growth at the base of the zone. Actually, conditions at the leading edge of the steam zone control its growth.

(2) Instances of zero (or near zero) injection rates often led to steam zone shrinkage. In reality, this shrinkage is condensation at the front end of the steam zone. As observed earlier, the Marx and Langenheim model does not consider this condensed zone, or heat loss from it, at all.

(3) The structural description of the reservoir (thicknesses) was somewhat haphazard in nature. A good working knowledge of where, and to what degree, override is occurring is essential for a study such as this. Without it, the choice of thickness scenarios was simply guesswork.

(4) Historically, this reservoir was developed in manner too heterogeneous for simple model matching. The turning on and off of steam, the changing quality of steam, the re-completion at wells--they all contributed to making this task difficult, if not impossible.

2.4.2 Vogel

Despite the obvious inadequacies of the Marx and Langenheim model, it provided reasonable, if not perfect, results. Unfortunately, the same cannot be said of the Vogel model. Based on the previous results, it was decided that variation of cyclic steam lag time was an unnecessary step. Only the one month lag was chosen for testing. Also, the irrelevance of differing thickness scenarios was established in an earlier section. A single case, therefore, was left to be examined, in contrast to the nine attempted with the Marx and Langenheim model.

The sample computer output at the end of Appendix B is the result of this run. Upon inspection of this output, the problem becomes clear. Three of the six well groupings produced no oil at all for the entire life of the flood, and the other three did not begin production until quite late in the life of the flood. Mathematically, this occurs because of the cumulative heat losses' functional reliance on *t*”‘. The rate of heat loss, therefore, is dependent on (1/ *t*)”‘, which is disproportionately large at early times. This led to cumulative heat losses greater than heat input; hence, no steam zone growth and no oil produced. In Vogel's paper, he performed an example calculation based on a mature, five-year old reservoir. Because he never considered the initial part of the flood, he never ran into this problem.

In an effort to salvage something reasonable from this model, a new approach was attempted. By treating the reservoir as a single unit, rather than six superimposible ones, and presuming immediate overlay of steam from the time of first injection, it was hoped that a more realistic production profile could be achieved. Again, the same pattern of excess heat loss was seen, enough to prevent any oil production for the entire life of the project. It was therefore decided to drop the Vogel model at this point, and declare it unsuitable for this reservoir.

The failure of this model might be due to the theoretical deficiency pointed out in Section *2*. Vogel used his efficiency relationship, which we pointed out as flawed in its ambiguous definition of steam zone thickness, to establish an efficiency curve similar to those of Prats and Myhill-Stegrneir (see Fig. 13 of Vogel). He cites the close agreement of all three of these curves as verification

of the validity of his model. It follows, then, that if his efficiency equation is in-
correct, the entire model itself may be in question.

3. ECONOMIC EVALUATION

3.1 General Methodology

The second half of this report deals with an economic evaluation of a surfactant-steam injection system based upon the results of the pilot project. This two-phase evaluation first dealt with the economics of the pilot project alone. This entailed setting pilot expenditures against incremental income from produced oil for determination of discounted cash flow and, ultimately, present worth.

Next, a commercial implementation of the surfactant-steam injection system was hypothesized. To do this, pilot results for incremental oil produced had to be extrapolated to a lease-wide basis. In addition, the facilities and costs for such a system had to be established. These costs were stripped of all those extraneous items that were strictly of academic and engineering interest, and not applicable to a commercial scale project.

The basic methodology of the evaluation was a simple discounted cash-flow analysis. It was applied on a quarterly basis, with discounting to mid-quarter. The scenario for the analysis was a mature steamflood project making the switch-over from steam to steam plus surfactant. In this context, only the incremental expenditures necessary for the switch-over had to be considered. These included capital costs for equipment purchased, and operating expenses for running the project. The positive cash flow resulting from the incremental oil produced less the negative cash flow due to the expenditures gave the necessary stream for discounting.

3.2 Economic Parameters

The following economic parameters and methodology were utilized in the evaluation:

(1) ACRS Depreciation Schedule. An accelerated five year depreciation program for intangible items was used. It allows 15% depreciation in the first year, 22% in the second year, and 21% per year thereafter.

(2) California Ad Valorem Tax. An approximate figure of 7% was used.

(3) Investment Tax Credit. This is applicable to all tangible investments; 10% was used.

(4) Windfall Profits Tax Rate. Heavy oil is classified under Tier III. This means a rate schedule of 30% in 1981, 27.5% in 1982, 25% in 1983, and 22.5% from 1984 to 1987 was in effect.

(5) Windfall Profits Tax Adjusted Base Price. This proved to be a very elusive figure; an approximation of $18/Barrel for the time span 1981-1987 was used.

(6) Oil Price. 14° gravity oil was assumed. The price schedule used was $21.55/barrel from July 1982 through February 1983, followed by $20.00/barrel thereafter. No further escalation rate was projected.

(7) Depletion Allowance. This was calculated as the lower of 15% gross working income and 50% of net income for depletion purposes. Net income for depletion purposes is defined as working interest revenue less operating costs, intangibles, ad valorem taxes, and depreciation. Depletion allowance is only allowed on the first 1000 barrels per day.

(8) Federal Income Tax Rate. 50% was used.

(9) Tangible Items. These are material goods such as pipe, pumps, and tanks. They are depreciable and subject to investment tax credit.

(10) Intangible Items and Operating Costs. These were treated identically as immediately expensed items.

3.3 Pilot Economics

The two critical input parameters that had to be determined for this evaluation were incremental costs and incremental oil produced. Table 3.1 gives a rough breakdown of the approximately $1.7 million spent on this project. Of these items only steam generation cost was deemed non-incremental. Because steam would have been generated for flood use even without the presence of the surfactant additive, this cost was excluded from the incremental economics. Total costs were then broken down on a month-to-month basis, and subsequently added to produce quarterly figures. Table 3.2 contains this resulting cash stream. All items other than a few tangible drilling expenditures were treated as expense items, hence the lumping of intangibles and operating costs in this table. Tangible drilling costs were calculated as 30% of total drilling costs.

TABLE 3.1
PILOT COSTS

Observation Well Drilling	$153,341
Steam generation cost	318.468
Surfactant cost	166,500
Royalty on injection	9,000
Cased hole logging	85,014
Tracer study	68,669
Injection profiles	77,341
GeothermEx consulting fees	162,034
CORCO salaries, Overhead, Fees Travel, communication and reports	485,066
Balance	184,066
TOTAL	$1,710,191

TABLE 3.2
TOTAL COST STEAM PILOT

Quarter		Tangible	Intangible Expenditures plus Operating Costs
1st	1981		$42,355
2nd	1981	$8,225	47,600
3rd	1981	40,520	166,091
4th	1981	3,233	107,529
1st	1982		88,066
2nd	1982	443	100,685
3rd	1982		186,206
4th	1982		207,643
1st	1983		105,604
2nd	1983		118,549
3rd	1983		123,378
4th	1983		78,899

Three scenarios for incremental production were considered: high, low, and expected. As indicated in Section 2, a low value of about 8500 barrels of oil was determined from the Marx and Langenheim model match. Figure 3.1 reveals a serious problem with this figure. On this graph, historical production rate for the test pattern is plotted against time. The second line represents predicted production rate based on the 8500 barrel figure. Clearly, the projected rate based on this minimal incremental oil figure is inconsistent with the historical rate. Thus, this production rate (and its resulting incremental) are not used.

As a result, it was decided to use the three extrapolated decline curves presented in Fig. 3.2 as the basis for incremental production calculations. The high and low lines were taken directly from Brigham, *et al.* (1984), while the

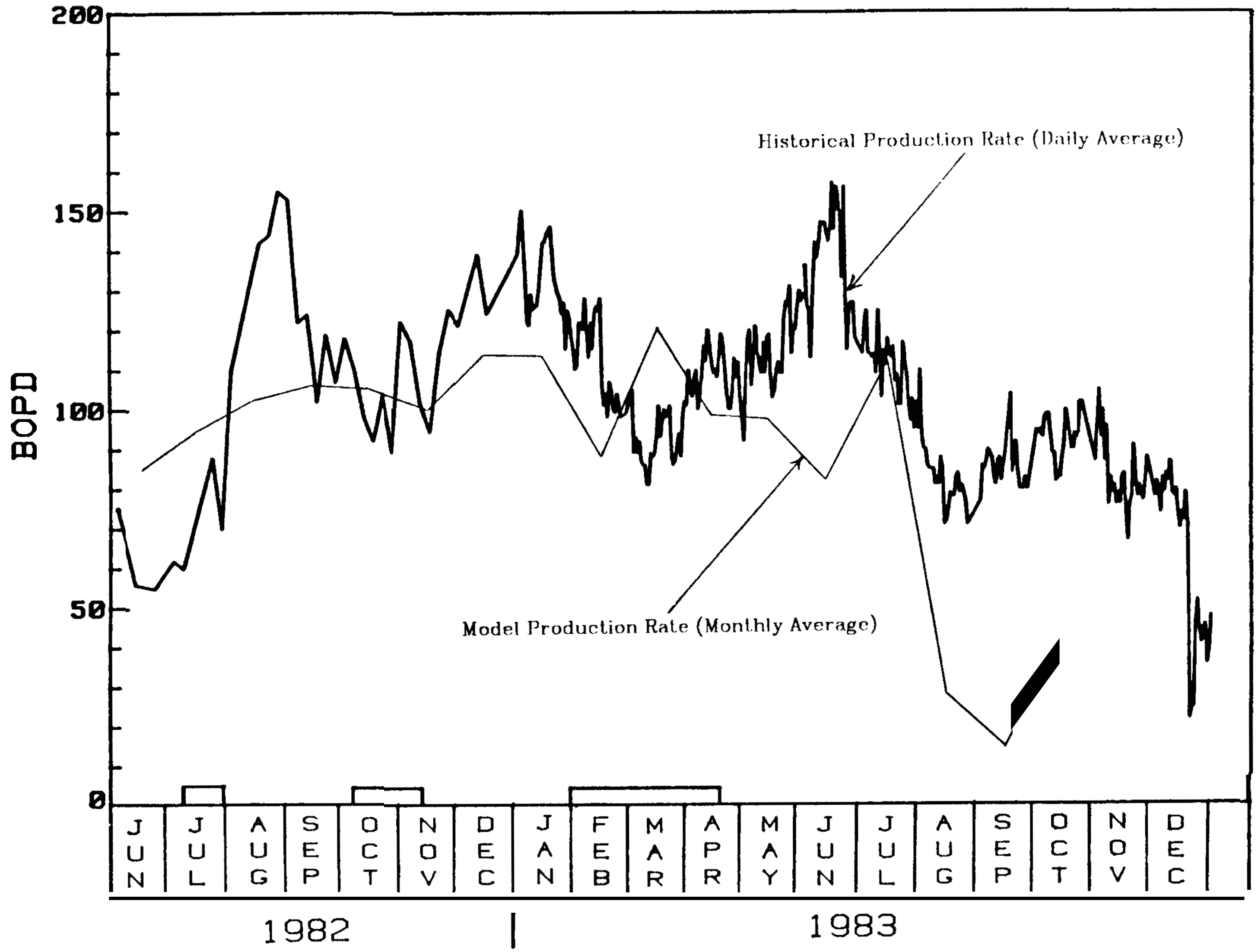

Fig. 3.1 Predicted and Historical Production Rate for Test Pattern

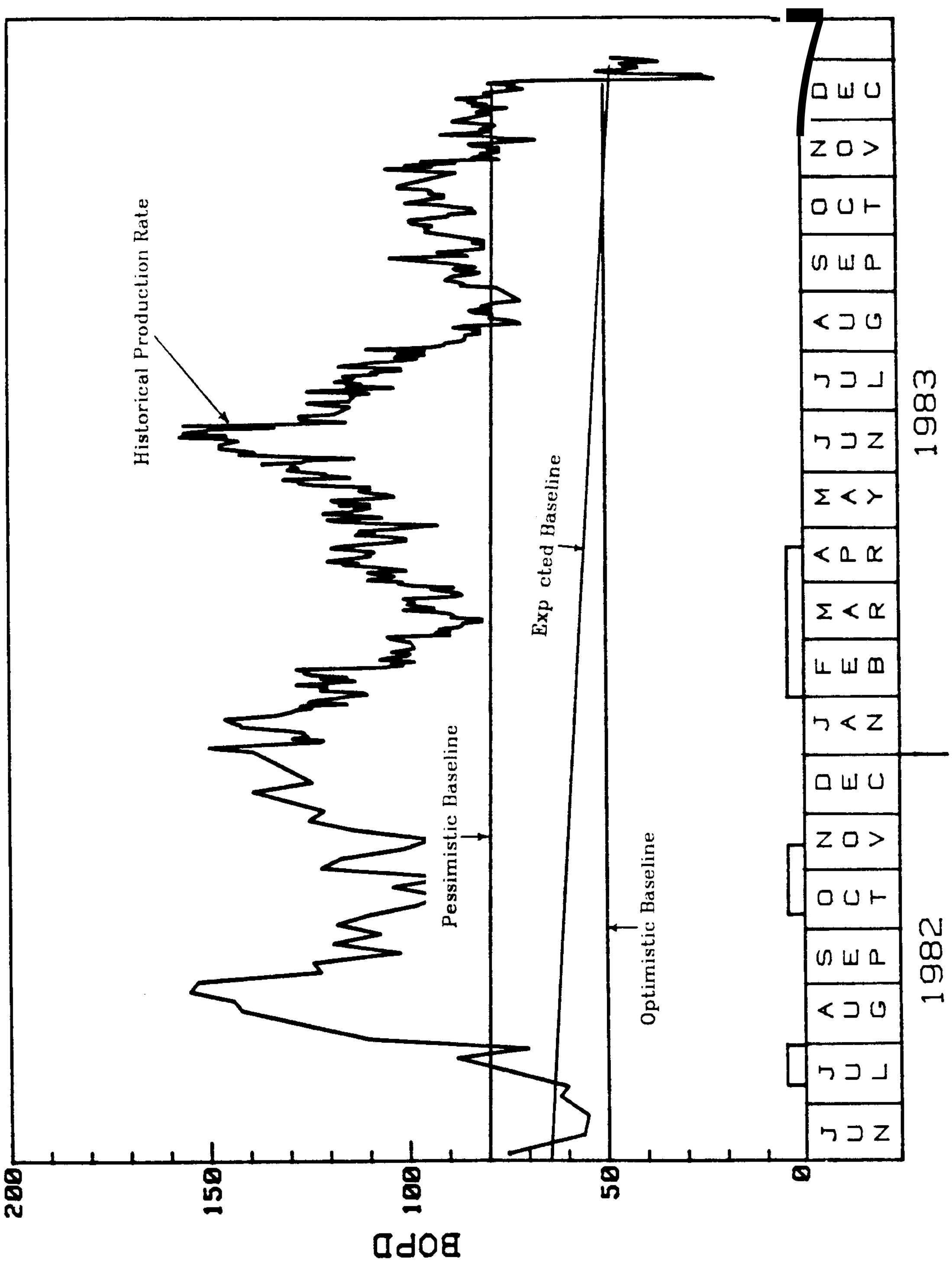

Fig. 3.2 Extrapolated and Historical Production Rate for Test Pattern

expected curve was based on further work performed by John Marcou after publication of the 1984 paper. These curves produced pilot incremental production of 14,000 barrels, 27,000 barrels, and 31,400 barrels, values which encompass the 16,000 to 26,000 barrel range derived by the Marx and Langenheim model. Table 3.3 summarizes the incremental production streams.

TABLE 3.3
INCREMENTAL PRODUCTION STREAM-PILOT

Quarter		Low Case (Barrels)	High Case (Barrels)	Expected Case (Barrels)
3rd	1982	2,722	6,082	4,281
4th	1982	3,391	6,127	5.231
1st	1983	2,636	5,372	4,780
2nd	1983	3,636	6.372	5,978
3rd	1983	1,194	3,930	3,778
4th	1983	421	3,557	2,952
Total		14,000	31,400	27,000

Table 3.4 gives the results of the present worth calculations for various discount rates. As expected, every case resulted in a large negative present worth. The conclusion to be drawn from this is straightforward. Pilot projects are not designed to make money: they are engineering exercises intended to generate information and understanding that may at some later date be applied to commercial scale projects. Their goal is not to make a profit in and of themselves, but to buy the necessary knowledge for future profits. In the next section, just such a profit-making scenario is examined.

TABLE 3.4
AFIT PRESENT WORTH OF PILOT PROJECT CASH FLOWS

Low Incremental Production

Discount rate (per quarter)	Present worth
2.5%	-$516,170
5.0%	-454,707
7.5%	-403,925

Expected Incremental Production

Discount rate (per quarter)	Present worth
2.5%	-$421,157
5.0%	-378,490
7.5%	-342,370

High Incremental Production

Discount rate (per quarter)	Present worth
2.5%	-$387,090
5.0%	-350,337
7.5%	-318.957

3.4 Lease-Wide Economics

Since the only tested injection procedure for this pilot was batch in nature, it was decided to design the commercial scale implementation as a batch process as well. Again referring to Brigham, *et al.* (1984), it was found that three separate slug tests were run. In each of the three tests, approximately 22,000 gallons of 14% active surfactant was injected. The first time, injection covered about one-half a month at a rate of 1 gpm; the second test covered a month at 0.5 gpm, and the third took a little over two months at 0.25 gpm. In the first test a large amount of nitrogen, about 300,000 scf, was added simultaneously. Subsequently, it was found that continuous nitrogen injection at 10 scfm was sufficient to ensure successful results. Although no formal optimization studies were performed, results seemed to indicate that:

(1) Production began to increase around one month following the start of injection.

(2) Production did not return to normal levels until approximately five to six months after the start of injection.

With these results in mind, the following scenario was hypothesized. The reservoir would be divided into three segments containing **6, 6,** and 5 injection wells, respectively. Injection would proceed in all the wells of the first segment for two months at the lowest flow rate tested, 0.25 gpm. Nitrogen would be simultaneously added at 10 scfm. Incremental production would begin one month after the start of injection and continue for five more months, producing a total of six months of injection plus production. In the meantime, the injection apparatus would be transferred to the second set of wells immediately after the completion of the first two month injection period. Injection in the third segment would follow two months later. Upon the completion of this period, the first segment would again be ready for injection. This methodology of scattered batch injection was more economically efficient because it allowed for the purchase of a single set of injection equipment sized to accommodate not the entire reservoir, but rather only 1/3 of the reservoir.

Just as in the case of the pilot economics, three incremental production scenarios were considered: high, low, and expected. The manner in which the actual flow numbers were calculated is described in Section 3.4.2. A three year project life was initially hypothesized, but a second case, involving a variable project life, was also tested.

3.4.1 Cost Parameters

Five separate items had to be considered in costing the steam plus surfactant injection project. These included the surfactant injection system, the nitrogen injection system, the surfactant requirement, the manpower requirement, and the testing/control parameters.

Surfactant Injection System This system consisted of two large polypropylene tanks, centrally located in the lease, for surfactant storage. These would be connected by two-inch lines to all injection wells on the lease, with a high pressure piston pump supplying the driving force for injection. Pressure gauge, screen filters, and flow meters are placed at various positions in the line, as well as control values for directing flow to the individual wells. Figure **3.3** presents a schematic configuration of this set-up. Specification and costs of the individual items are given in Table 3.5, while Appendix H presents the calculations for the utility cost estimation.

Nitrogen Injection System For this system, a skid mounted portable nitrogen generator manufactured by the CM Kernp Company was the equipment of choice. The unit, called the MSA4, requires input of natural gas, electric power,

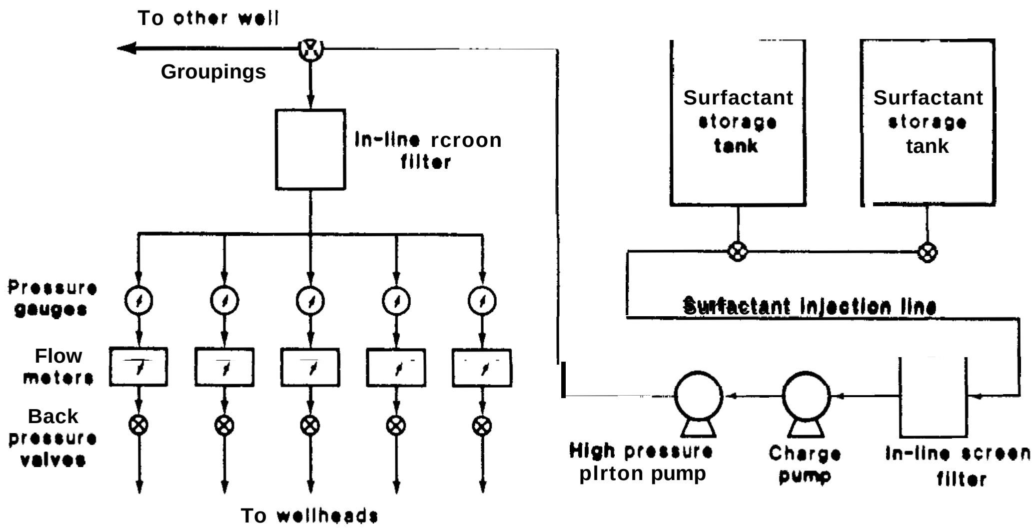

Fig. 3.3 Surfactant Injection System

and low pressure cooling water. High purity nitrogen is produced at rates up to 75 scfm and at pressures up to 800 psi. Thus, this unit can feed as many as seven wells at the required 10 scfm rate. Quantities of CO, H_2, and CO_2 are also produced. The presence of an internal scrubbing unit, however, reduces these impurities to such trace quantities that corrosion needn't be considered a problem.

The cooling requirement of the system would be satisfied with excess produced water. This water is stored in a large, centrally located polypropylene tank and delivered through flexible hose via centrifugal pump to the unit. The high pressure nitrogen emerging from the generator charges two very large cylinders, which serve as storage facilities until discharge into the injection wells. In this manner, the generator can be run most efficiently--at a maximum load for the shortest time possible. The schematic of this setup is shown in Fig. **3.4,** and the individual items' specifications and costs are given in Table 3.6.

TABLE 3.5
SURFACTANT INJECTION SYTSTEM

	Item	Unit Cost	Number of Units	Total Cost
Capital Expenditures:				
	20,000 gallon polypropylene tank	$24,000	2	$48,000
	High pressure piston pump	11,000	1	22,000
	Charge pump	2,000	1	2,000
	Flow meter	1,500	17	25,500
	Pressure relief valve	1,000	17	17,000
	Valve	300	5	1,500
	Coarse screen filter	2,000	4	8,000
	Pressure gauge	400	17	6,800
	2" tubing	84/ft	10,000 ft	40,000
			TOTAL	$170,800
Operating costs:				
	Electric Power (as of 6/84)	8.18¢/Kw-hr	11,383 Kw-hr/quarter	$931/quarter

Utility cost calculations are again presented in Appendix H.

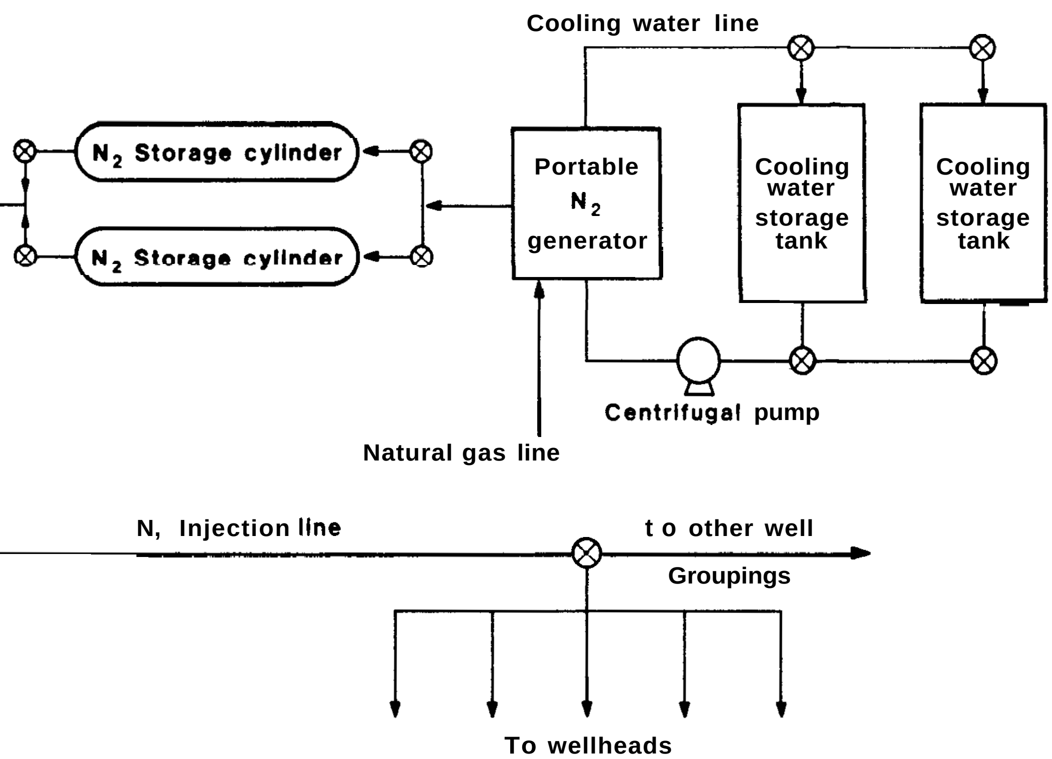

Fig. 3.4 Nitrogen Injection System

Surfactant Requirement Over the first two months period, six injection wells would receive 0.25 gpm of 14%active Suntech IV. The next two months, another **six** wells would be injected. For the final two months, only five wells are injected. This leads to cycles of 131,320 gallons, 131,328 gallons, and 109,440 gallons of surfactant injected over each six month period. At $1.45/gallon, this produced bimonthly surfactant costs of $190,426, $190,426, and $158,688 every six months. In addition, a royalty tariff of 10 cents/lb of 100% active surfactant injected was included. This led to bimonthly costs of $16,666, $16,666, and

TABLE 3.6
NITROGEN INJECTION SYSTEM

	Item	Unit Cost	Number of Units	Total Cost
Capital Expenditures:				
	Nitrogen generator	8150,000	1	$150,000
	20,000 gallon polypropylene tank	24,000	2	48,000
	N_2 cylinders	2,000	2	4,000
	Centrifugal pump	1,000	1	1,500
	Valve	300	5	1,500
	2" tubing	$4/ft	10,000 ft	40,000
	Water hose	$1/ft	1,500 ft	1,500
			TOTAL	$246,000
Operating costs:				
	Electric power (as of 6/84)	8.18¢/Kw-hr	101,771 Kw-hr/quarter	$8325/quarter
	Natural gas (as of 6/84)	$7.18/mscf	1806 mscf/quarter	$12,967/quarter

$13,888.

Manpower Requirement It was hypothesized that two field support personnel and one full-time engineer would be required to monitor the project. A salary of $40,000/year was assigned to each field support personnel and $50,000/year to the engineer. These were doubled to account for overhead and benefits, producing a total of $260,000/year for manpower.

Testing/Control Parameters Four different items come under this category. These included C/O and temperature logs, injection profile tests, and a reservoir study. These are costs which a large oil company would not hesitate to spend to insure the success of the project. Small independents, with a weaker cash flow position, would probably ignore them. Hence, two scenarios were set forth--large company and small company. The small company scenario ignored testing/control parameters but included depletion, under the assumption that their 1000 barrel/day allowance would not have been used up elsewhere. The large company scenario excluded depletion but included testing/control expenditures. In general, the inclusion of such costs would likely lead to an increased incremental production schedule. Since the extent of this increase was not a focal point of this study, identical production scenarios were used for both large and small company cases, thereby underestimating the economics of the large company case. The schedule for these expenditures is shown in Table 3.7.

A final word on cost parameters. A 6%/year escalation factor was included for manpower costs, logging/testing costs, and utility costs. It was not included for surfactant costs, however, because it was presumed likely that due to the increasing number of vendors entering the surfactant market, surfactant costs would likely remain stable. Appendix H details the calculation of the quarterly cost stream, which itself is given in Table 3.8.

TABLE 3.7
TEST / CONTROL COSTS

Item	Unit Cost	Number of Units	Total Cost
C/O Log (as of 6/84)	$5,000	1/quarter	$5,000/quarter
Temperature Log (as of 6/84)	2,000	1/quarter	2,000/quarter
Injection Profile (as of 6/84)	2,100	1/quarter	3,100/quarter
Reservoir Engineering Study	100,000	1	100,000

3.4.2 Incremental Production

Calculation of the incremental production streams were again based upon the extrapolated decline curves of Fig. 3.2. First, each of the three incremental production figures was divided by the total surfactant injected. This produced the parameter barrels of oil incrementally produced/gallon surfactant injected. This was then multiplied by total gallons to be injected during the hypothesized two-month slug period, to give the total incremental production produced by each slug. This was subsequently divided by the five month production period to arrive at the monthly incremental production per injector. Finally, these results were multiplied by the number of injection wells on surfactant during any given period to get the final figure of lease-wide monthly incremental production. The calculation for each of the three cases is presented in Appendix I, and the resultant production streams are given in Table 3.9. It should be noted that this methodology for deriving the production stream is conservative in that it ignores the variation of rate within the incremental production stream. Typically, of the total incremental oil produced, most comes very quickly following injection, i.e., production rate immediately increases, then slowly returns to

TABLE 3.8
TOTAL COST STREAM-LEASE-WIDE EVALUATION

A. Small company scenario--no test/control items.

Quarter	Tangible Expenditures	Intangible Expenditures
1st	$416,800	$397,861
2nd		363,678
3rd		398,533
4th		364,361
1st		403,125
2nd		368,963
3rd		403,838
4th		369,686
1st		408,706
2nd		374,565
3rd		409,462
4th		375,334

B. Large company scenario--with test/control items.

Quarter	Tangible Expenditures	Intangible Expenditures Plus Operating costs
1st	$416,800	$506,961
2nd		372,915
3rd		407,908
4th		373,877
1st		412,783
2nd		378,766
3rd		413,788
4th		379,786
1st		418,957
2nd		384,970
3rd		420,023
4th		386,053

TABLE 3.9
INCREMENTAL PRODUCTION STREAM-LEASE-WIDE EVALUATION

Quarter	Low Case (Barrels)	High Case (Barrels)	Expected Case (Barrels)
1st	10,593	23,759	20,430
2nd	36,194	81,177	69,802
3rd	34,428	77,216	66,396
4th	40,607	91,076	78,314
1st	34,428	77,216	66,396
2nd	40,607	91,076	78,314
3rd	34,428	77,216	66,396
4th	40,607	91,076	78,314
1st	34,428	77,216	66,396
2nd	40,607	91,076	78,314
3rd	34,428	77,216	66,396
4th	40,607	91,076	78,314

normal. By flattening the incremental production profile, revenue has been effectively pushed back in time, thereby creating less profitability on a present worth basis.

3.4.3 Results and Discussion

The results of the present worth analysis for each of the six cases are presented in Figs. 3.5 and 3.6. These graphs present a plot of AFIT discounted cash flow against quarterly discount rate. An entire spectrum of discount rates, ranging from 2.5%/quarter (10%/year) to 20%/quarter (80%/ year), was used in this analysis in an attempt to define that point at which discounted cash flow becomes zero--the internal rate of return of the project. Note that in each of the six cases this point was never achieved, indicating that the IRR was in all cases greater than 80%.

Table 3.10 approaches the analysis from a different viewpoint. In all cases, a three year project life was assumed. In general, lengthening this duration would yield more favorable results as long as revenues continued to outstrip operating costs. Shortening it, on the other hand, would no doubt decrease the present worth because of the large initial capital outlay at time zero. Table 3.10 lists the discounted AFIT payback period of each case at each discount rate. These figures represent the total number of quarters necessary to achieve a zero present worth at the given discount rate, or the minimum required project life to attain an IRR equal to the discount rate. Most major oil companies consider 20% to 30% per year as a satisfactory return on investment, figures which were achieved in less than 1.5 years even in the most pessimistic cases tested.

One final affirmation of the economic success of this project entailed determination of the minimum incremental production necessary to achieve the 20% to 30% rate of return just mentioned. Recall that the three cases of incremental

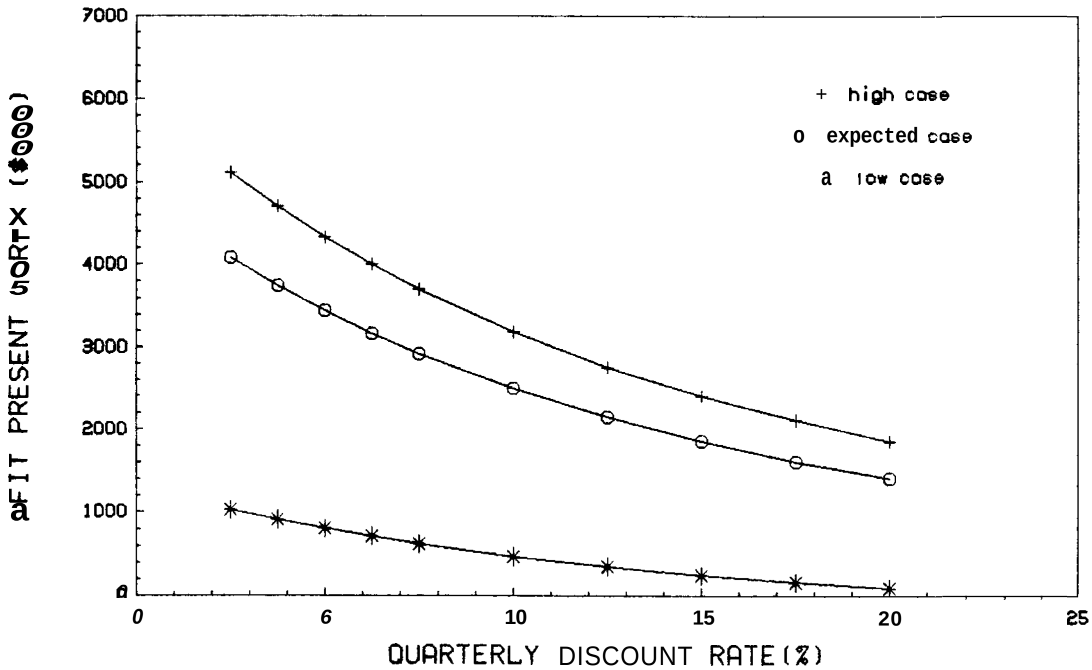

Fig. 3.5 Present Worth vs. Discount Rate–Large Company Scenario

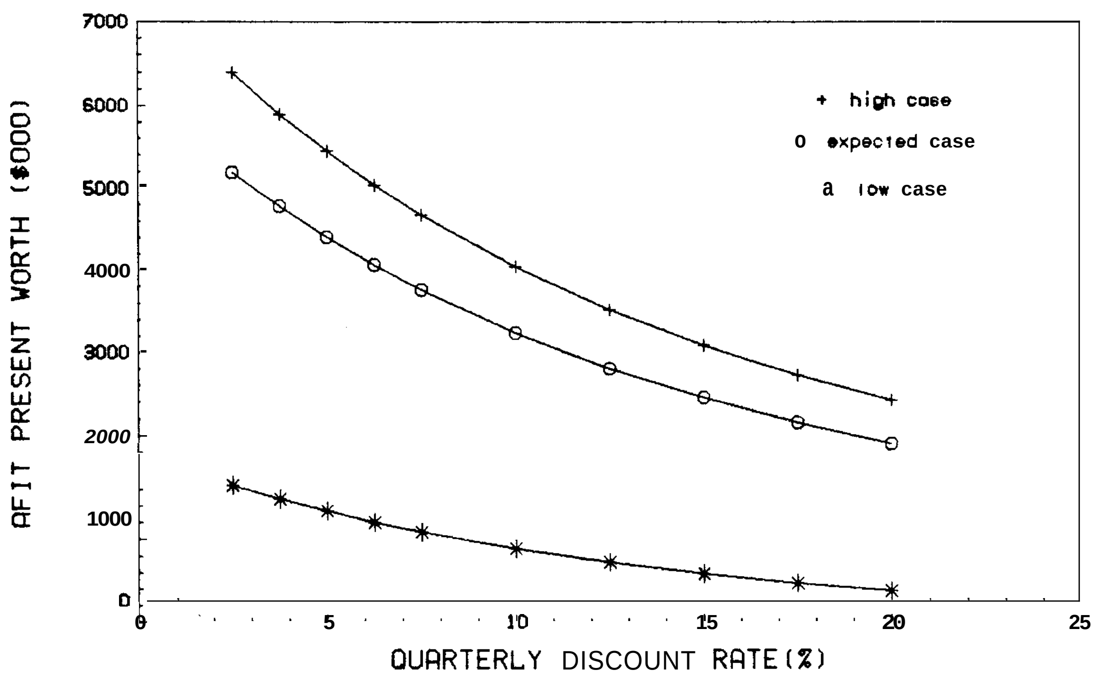

Fig 3.6 Present Worth vs. Discount Rate–Small Company Scenario

TABLE 3.10
DISCOUNTED AFIT PAYBACK FOR LEASE-WIDE PROJECT

Low Incremental Production

Discount rate (per quarter)	Discounted AFIT payback (quarters) Large company	Small company
2.5%	4.9	3.5
5.0%	5.2	3.6
7.5%	5.4	3.7
10.0%	5.8	3.8

Expected Incremental Production

Discount rate (per quarter)	Discounted AFIT payback (quarters) Large company	Small company
2.5%	2.0	1.7
5.0%	2.0	1.7
7.5%	2.1	1.8
10.0%	2.1	1.8

High Incremental Production

Discount rate (per quarter)	Discounted AFIT payback (quarters) Large company	Small company
2.5%	1.8	1.5
5.0%	1.0	1.5
7.5%	1.8	1.6
10.0%	1.8	1.6

production, high, low, and expected, were based on pilot results of 31,400 barrels, 14,000 barrels, and 27,000 barrels of incrementally produced oil. Graphing these values against AFIT present worth and extrapolating to zero should yield the necessary production figure. This is done for the large company scenario in Fig. **3.7** for quarterly discount rates of 5%, 6.25%, and 7.5%. The resultant volumes were all approximately 10,500 barrels or less. This establishes that even if the original low assessment of incrementally produced oil from the pilot had been optimistic, a cutback of up to 25% would still have produced economically favorable results.

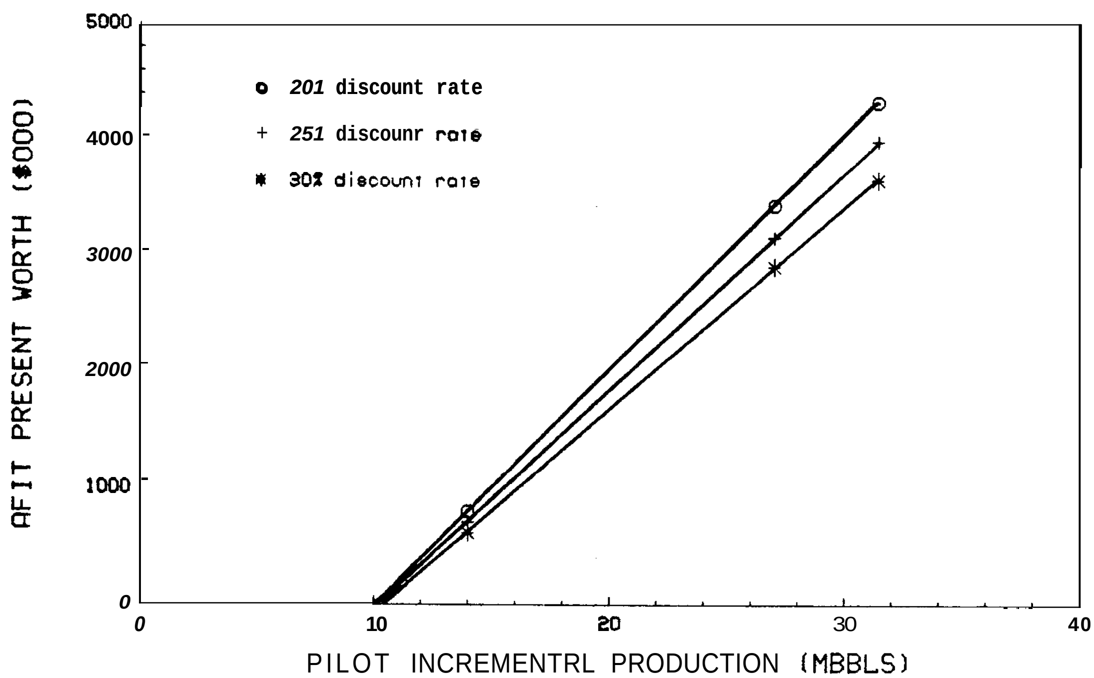

Fig. **3.7 Minimum Pilot Incremental Oil to Achieve 20% to 30% IRR**

It is clear that all aspects of the presented analysis imply that a lease-wide implementation of a steam plus Suntech IV injection system would be an overwhelming financial success. Of course, only a single, simple scenario was utilized in this study. Multiple injection rates, different injection systems, buy vs. rent decisions--all were left untested. It is important to remember, however, that the purpose here was not to perform an optimization study for steam plus surfactant injection, but rather to establish the economic feasibility of such a system. It is the opinion of this author that the above results achieved this goal.

Also, it should be noted that these results are based upon injection and production scenarios similar to those used in the pilot. From the results of the pilot it seems that lower surfactant injection rates than those actually used could still produce a considerable amount of incremental oil. The use of surfactant was not optimized in this test, nor was the test run with surfactant optimization as a goal. Further pilot tests designed to perform this optimization could no doubt provide additional (and improved) scenarios for the commercial scale implementation of this project.

4. CONCLUSIONS AND RECOMMENDATIONS

The following conclusions and recommendations can be drawn from this study.

Conclusions

(1) The Marx and Langenheim steamflood model, though a simple frontal displacement one, provided an adequate description of the McManus Lease steamflood project.

(2) Incremental production from the test pattern due to the injection of Suntech IV predicted by the Marx and Langenheim model was consistent with the results calculated in Brigham, *et al.* (1984) via decline curve extrapolation. That is, values ranged from 14,000 incremental barrels to 31,400 incremental barrels.

(3) Minimal incremental production predicted by slope matching the Marx and Langenheim model with lease history after 6/81 produced a figure which, although reasonable in and of itself, proved to be unrealistic when compared to the historical test pattern rate curve.

(4) The Vogel overlay steamflood model gave no reasonable history match results and was deemed inapplicable to the McManus Lease.

(5) A flaw in Vogel's derivation of his model pertaining to an ambiguous definition of formation thickness may have been the cause for the poor results obtained with this model.

(6) Incremental economic analysis of the pilot showed, as expected, a net loss of money.

(7) Incremental economic analysis of the project on a lease-wide basis was performed using a single injection scenario and three possible levels of incremental production. In all cases, by all criteria, these analyses

proved the economic feasibility of such a lease-wide project.

Recommendations

(1) With reference to the steamflood model match of the McManus Lease, it seems unlikely that more sophisticated methodology would have proved useful for this reservoir given the heterogeneous operating conditions under which it was produced. In preparing for future field tests, this factor should be taken into consideration. Test sites should be chosen to facilitate the best possible engineering studies available. This means choosing a reservoir that has been operated under reasonably constant conditions, and whose historical data have been accurately recorded. Under such a scenario more sophisticated models, including reservoir simulation studies, could be attempted in order to more accurately estimate incremental oil production due to the surfactant.

(2) With reference to the economic analysis, additional scenarios could be tested in an attempt to optimize the profitability of the commercial scale steam plus surfactant injection project.

(3) Other pilot tests of field cases should be run in which the rates and durations of surfactant injected are varied over a range wide enough to optimize this parameter.

5. NOMENCLATURE

A Area, ft^2

B_o Oil formation volume factor, reservoir bbls/surface bbls

C Heat capacity, Btu/lb$_m$ "F

C_o Heat capacity of oil, Btu/lb$_m$ "F

C_w Heat capacity of water, Btu/lb$_m$ °F

C_σ Heat capacity of rock matrix, Btu/lb$_m$ °F

E_c Capture efficiency, dimensionless

E_h Reservoir heating efficiency, dimensionless

f_q Fractional volume of quartz in matrix, dimensionless

f_s Steam quality, dimensionless

f_z Heat flux across horizontal interface, Btu/hr-ft^2

h Height, ft

h_n Net thickness of layer, ft

h_t Total or gross thickness of layer, ft

K Thermal conductivity, Btu/ft-hr-°F

K_m Thermal conductivity of quartzitic sand, Btu/ft-hr-°F

K_R Thermal conductivity of reservoir, Btu/ft-hr-°F

K_s Thermal conductivity of adjaent zones, Btu/ft-hr-°F

K_1 Thermal conductivity of overburden, Btu/ft-hr-°F

K_2 Thermal conductivity of underburden, Btu/ft-hr-°F

L_v Latent heat of vaporization, Btu/lb$_m$

M_R Volumetric heat capacity of reervoir, Btu/ft^3 °F

M_o Volumetric heat capacity of oil, Btu/ft^3°F

M_s	Volumetric heat capacity of adjacent zones, Btu/ft^3 "F
M_w	Volumetric heat capacity of water, Btu/ft^3 "F
M_σ	Volumetric heat capacity of rock matrix, Btu/ft^3 "F
Q	Heat content, Btu
Q_s	Heat content of steam zone, Btu
Q_t	Total heat injected into the ground, Btu
$\dot{Q}_i$	Rate of heat injection, Btu/hr
$\dot{Q}_l$	Rate of heat loss, Btu/hr
S_{oi}	Initial oil saturation, dimensionless
S_{or}	Residual oil saturation, dimensionless
S_{st}	Steam saturation, dimensionless
S_{wr}	Residual water saturation, dimensionless
t	Time, hr
t_D	Dimensionless time
T_s	Temperature of steam zone, °F
T_f	Ambient temperature of reservoir, "F
$U(t - t_j)$	Unit function, 0 if $t < t_j$ and 1 if $t > t_j$
V_s	Volume of steam zone, ft^3
z	Vertical length coordinate of reservoir, ft
α_s	Thermal diffusivity of adjacent zones, ft^2/day
α_1	Thermal diffusivity of overburden, ft^2/day
α_2	Thermal diffusivity of underburden, ft^2/day
ΔQ_j	Change in heat injection rate since time period j, Btu/hr
Δs_o	Change in oil saturation, dimensionless

ΔT_i	Difference between steam zone and ambient reservoir temperature
$\Delta(\Delta T_i)_y$	Change in temperature difference between steam and ambient reservoir since time period j, °F
γ	Specific gravity, dimensionless
γ_o	Specific gravity of oil, dimensionless
θ	Prats' parameter in his dimensionless time function, $hr^{-1/2}$
ρ	Density, lb_m/ft^3
ρ_o	Density of oil, lb_m/ft^3
ρ_{st}	Density of steam, lb_m/ft^3
ρ_w	Density of water, lb_m/ft^3
ρ_σ	Density of rock matrix, lb_m/ft^3
φ	Porosity, dimensionless

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APPENDIX A. MARX AND LANGENHEIM COMPUTER PROGRAM

This appendix contains a program listing of Marx4.f, the computer program written to perform the Marx and Langenheim frontal displacement steamflood calculation, with Ramey's modification for variable injection rates. As commented in the program, the month-by-month injection rates may be printed out via a slight modification of the program. This was not done so in this version because of the great length of the data.

Following the program listing is a sample output for this model.

A.1 Program Listing

```
************************************************************************
************************************************************************
**********                      MARX4.F                       **********
**********   A COMPUTER PROGRAM THAT PERFORMS OIL PRODUCTION   **********
**********   PREDICTION BASED ON MARX AND LANGENHEIM'S STEAM   **********
**********   FLOOD MODEL WITH RAMEY'S CORRECTION FOR VARIABLE  **********
**********                HEAT INJECTION RATES                 **********
************************************************************************
************************************************************************
C First, the necessary arrays are dimensioned, and storage files opened.
      implicit real*8(a-h,o-z)
      real*8 lv(72),ms,mr
      dimension qr(72), wi(72),cw(72),ts(72),fs(72),lv(72),hpr(72)
      dimension td(72),time(72),delqr(72),delwi(72),tint(72),wib(72)
      dimension win(1Ø,72),ll(72),q(72),pop(1Ø,72),nip(1Ø),totoil(72)
      dimension steam(1Ø,72),prodoil(1Ø,72),stinj(1Ø,72)
      dimension totsteam(72)
      open(unit=3,file='result')
      rewind(unit=3)
      open(unit=4,file='grap')
      rewind(unit=4)
C This begins the interactive portion of the program, in which the user is
C requested all the necessary reservoir properties, thermal and non-thermal.
C This data may easily be input with a file as well.
      write(6,15)
   15 format('number of segments')
C The variable kseg and its accompanying do loop allows for running all six
C well groupings at the same time.  kseg is simply the number of well
C groupings utilized per run.
      read(5,*) kseg
      do 17 ll5=1,kseg
      do 18 m=1,72
      qr(m)=Ø.Ø
      wi(m)=Ø.Ø
      cw(m)=Ø.Ø
      ts(m)=Ø.Ø
      fs(m)=Ø.Ø
      lv(m)=Ø.Ø
      hpr(m)=Ø.Ø
      td(m)=Ø.Ø
      time(m)=Ø.Ø
      delqr(m)=Ø.Ø
      delwi(m)=Ø.Ø
      tint(m)=Ø.Ø
      wib(m)=Ø.Ø
      ll(m)=Ø.Ø
      q(m)=Ø.Ø
   18 continue
      opold=Ø.Ø
      qold=Ø.Ø
      vsold=Ø.Ø
      write(6,2Ø)
   20 format('capture efficiency(fraction)?')
      read(5,*) ec
      write(6,21)
   21 format('formation volume factor?')
      read(5,*) bo
      write(6,22)
   22 format('initial oil saturation(fraction)?')
      read(5,*) soi
      write(6,23)
   23 format('residual oil saturation(fraction)?')
      read(5,*) sor
      write(6,24)
```

```
   24 format('net pay thickness(ft)?')
      read(5,*) hn
      write(6,25)
   25 format('total pay thickness(ft)?')
      read(5,*) ht
      write(6,26)
   26 format('porosity of the reservoir(fraction)?')
      read(5,*) porpay
      write(6,27)
   27 format('temperature of undisturbed reservoir(deg f)?')
      read(5,*) tr
      write(6,28)
   28 format('thermal diffusivity of adjacent formations(sq ft/day)?')
      read(5,*) alpha
      write(6,3Ø)
   30 format('number of time intervals?')
      read(5,*) ni
      nip(115)=ni
      write(6,31)
   31 format('size of time step(days)?')
      read(5,*) tstep
      write(6,32)
   32 format('volumetric injection rate per interval(bbl/day), enthalpy
     *code?')
      do 33 j=1,ni
      read(5,*) win(115,j),ll(j)
      wib(j)=win(115,j)/3Ø.4
      wi(j)=wib(j)*35Ø.376
   33 continue
C The following loops contain codes which trigger the correct enthalpy
C content and downhole temperature for each months injection rate.
      do 38 j=1,ni
      if(ll(j).eq.1) then
      q(j)=89Ø.Ø
      ts(j)=316.Ø
      end if
      if(ll(j).eq.2) then
      q(j)=9Ø6.Ø
      ts(j)=321.Ø
      end if
      if(ll(j).eq.3) then
      q(j)=9Ø5.Ø
      ts(j)=346.Ø
      end if
      if(ll(j).eq.4) then
      q(j)=9Ø9.Ø
      ts(j)=372.Ø
      end if
      if(ll(j).eq.5) then
      q(j)=912.Ø
      ts(j)=382.Ø
      end if
   38 continue
      write(6,42)
   42 format('fraction of heat injected that is produced per interval?')
      read(5,*) hpr(1)
      do 43 j=1,ni
      hpr(j)=hpr(1)
   43 continue
      write(6,44)
   44 format('length of time of each interval(days)?')
      read(5,*) tint(1)
      do 45 j=1,ni
      tint(j)=tint(1)
```

```
   45 continue
      write(6,46)
   46 format('volumetric heat capacity of reservoir(btu/cu ft deg f)?')
      read(5,*) mr
      write(6,47)
   47 format('vol heat capacity of adjacent formations(btu/cu ft deg f)
     *?' )
      read(5,*) ms
C The input parameters are next printed out both on the screen and in the
C result file as a check on their accuracy.
      write(6,5Ø) mr,ms,tr,alpha,porpay,soi,sor,hn,ht,bo,ec
      write(3,5Ø) mr,ms,tr,alpha,porpay,soi,sor,hn,ht,bo,ec
   50 format(25x,'RESERVOIR AND STEAM PROPERTIES',//,
     *'volumetric heat capacity of reservoir(btu/cu ft-deg f)',t67,f12.2
     *,/,
     *'volumetric heat capacity of adjacent formations(btu/cu ft-deg f)'
     *,t67,f12.2,/,
     *'temperature of undisturbed reservoir(deg f)',t67,f12.2,/,
     *'thermal diffusivity of adjacent formations(sq ft/day)',t67,f12.2
     *,/,
     *'porosity',t67,f12.2,/,
     *'initial oil saturation',t67,f12.2,/,'residual oil saturation',t67
     *,f12.2,/,'net pay thickness(ft)',t67,f12.2,/,
     *'total pay thickness',t67,f12.2,/,
     *'oil formation volume factor',t67,f12.2,/,
     *'capture efficiency',t67,f12.2,//)
C Input parameter5 that vary from month to month may also be printed out.
C Here, however, that step has been bypassed because of the lengthiness
C of that data.  Removal of the 'go to 60' statement will implement this
C printed output.
      go to 60
      do 60 i=1,ni
      write(6,51) i,tint(i),wib(i),fs(i),lv(i),cw(i),ts(i),hpr(i)
      write(3,51) i,tint(i),wib(i),fs(i),lv(i),cw(i),ts(i),hpr(i)
   51 format(25x,'INTERVAL # ',i2,/,'time(days)',t6Ø,f12.2,/,
     *'injection rate(bbls/day)',t6Ø,f12.2,/,'quality of steam',
     *t6Ø,f12.2,/,'latent heat of vaporization(btu/lb)',t6Ø,f12.2,
     */,'heat capacity of steam(btu/lb-deg f)',t6Ø,f12.2,/,
     *'temperature of steam(deg f)',t6Ø,f12.2,/,
     *'fraction of injected heat produced',t6Ø,f12.2,//)
   60 continue
C Here, the downhole heat injected is calculated for each month.
      do 100 i=1,ni
      qr(i)=wi(i)*q(i)
  100 continue
C The multiplicative factor for determining dimensionless time is calculated
C in this step.
      c=4.Ø*((ms/mr)**2)*(alpha/(ht**2))
      d=1.Ø/c
      tcum=Ø.Ø
C The following loop calculates and stores time and dimensionless time for
C every monthly interval.
      do 200 i=1,ni
      tcum=tcum+tint(i)
      td(i)=c*tcum
      time(i)=tcum
  200 continue
C Next, the change in the rate of heat input over each month is calculated
C and stored.  The same is done with the rate of barrels of water equivalent
C injected.
      delqr(1)=qr(1)
      delwi(1)=wi(1)
      if (ni.eq.1) go to 300
      do 300 i=1,ni-1
```

```
      delqr(i+1)=qr(i+1)-qr(i)
      delwi(i+1)=wi(i+1)-wi(i)
  300 continue
C Here, the headings for the output tables are being printed.
      write(3,35Ø)
      write(6,35Ø)
  350 format('time(days)',5x,'cum steam injected',5x,
     *'cum oil produced',5x,'size of steam zone',5x,'incremental oil')
      write(3,351)
      write(6,351)
  351 format(15x,'(bbls water equiv)',11x,'(bbls)',12x,'(acre-ft)',
     *12x,'(bbls)',//)
C This starts the important calculation.  Time is set equal to the first
C time step, and the dimensionless equivalent is calculated.
      tt=tstep
      mm=1
  390 ttd=c*tt
C This loop performs the superposition calculation.  It checks whether the
C change in time over the present time step has passed one of the previously
C derived rate change intervals.  If it has, the necessary superposition
C calculation is performed.  If not, a standard calculation is performed.
      do 400 i=1,ni
      l=ni+1-i
      j=l
      if(ttd.gt.td(l)) go to 450
  400 continue
C This is the standard, non-superposition calculation.
      qcum=d*delqr(1)*g(ttd)
      wcum=delwi(1)*tt
      gg=g(ttd)
      temp=ts(1)
      go to 700
C This is the superposition calculation.
  450 qcum=d*delqr(1)*g(ttd)
      wcum=delwi(1)*tt
      do 600 i=1,j
      dt=ttd-td(i)
      dtime=tt-time(i)
      qcum=qcum+d*delqr(i+1)*g(dt)
      wcum=wcum+delwi(i+1)*dtime
  600 continue
C At this point, incremental reservoir heat, qinc, is calculated for each
C month by subtraction, so that incremental steam zone volume may be determined.
C vsinc is this incremental volume, and vs is the cumulative volume.
      temp=ts(j+1)
  700 qinc=qcum-qold
      write(6,7Ø1) qcum
  701 format(e13.5)
      vsinc=qinc/(mr*(temp-tr))*(1.Ø/4356Ø.Ø)
      vs=vsinc+vsold
      vw=wcum/35Ø.376
C op is the cumulative oil produced and is calculated in the following
C step.  If cumulative oil at any month is less than the previous month,
C the cumulative for that month remains unchanged, and the incremental
C for that month is set to zero.
      op=7758.Ø*porpay*(hn/ht)*(soi-sor)*ec*vs/bo
      if(op.lt.opold) op=opold
      pop(115,mm)=op
      steam(115,mm)=vw
      difop=op-opold
      write(3,75Ø) tt,vw,op,vs,difop
      write(6,75Ø) tt,vw,op,vs,difop
  750 format(2x,f6.1,1Øx,f1Ø.1,11x,f9.1,14x,f9.5,11x,f9.1)
C The old values of oil produced, steam zone volume, and heat in the reservoir
```

```
C are now set to the latest calculated values, and the time step is increased
C to the next month.  The program then loops back to perform the entire
C calculation again.  When the total number of intervals exceeds that which
C had been previously input as the maximum, the program proceeds to the next
C well grouping.
      opold=op
      vsold=vs
      qold=qcum
      tt=tt+tstep
      mm=mm+1
      if(tt.le.time(ni)) go to 390
   17 continue
C The following set of calculations adds the separate well groupings results
C and prepares an input file for automatic graphing by computer.
      do 800 k=1,kseg
      mn=72-nip(k)
      do 810 j=1,mn
      prodoil(k,j)=Ø.Ø
      stinj(k,j)=Ø.Ø
  810 continue
      do 820 j=1,nip(k)
      mmn=mn+j
      prodoil(k,mmn)=pop(k,j)
      stinj(k,mmn)=steam(k,j)
  820 continue
  800 continue
      do 900 n=1,72
      do 910 k=1,kseg
      totoil(n)=totoil(n)+prodoil(k,n)
      totsteam(n)=totsteam(n)+stinj(k,n)
  910 continue
  900 continue
      jkl=29
      write(4,92Ø) jkl
  920 format(i5)
      do 940 j=44,72
      write(4,93Ø) totsteam(j),totoil(j)
  930 format(2f13.4)
  940 continue
      stop
      end
C This is a defined function utilized in the Marx and Langenheim solution.
      function g(a)
      implicit real*8(a-h,o-z)
      b=a**Ø.5
      pi=3.1415927
      g=2.Ø*((a/pi)**Ø.5)-1.Ø+(dexp(a)*derfc(b))
      return
      end
```

A.2 Sample Output

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	36.00
volumetric heat capacity of adjacent formations(btu/cu ft-deg f)	41.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of adjacent formations(sq ft/day)	0.94
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	307.00
total pay thickness	356.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	5840.0	2528.0	3.77860	2628.0
60.8	57636.0	24896.4	37.21330	22368.4
91.2	105152.0	44966.4	67.21248	20070.0
121.6	105152.0	44966.4	66.09598	0.
152.0	105152.0	44966.4	65.31076	0.
182.4	105152.0	44966.4	64.66541	0.
212.8	105152.0	44966.4	64.10642	0.
243.2	105152.0	44966.4	63.60796	0.
273.6	105152.0	44966.4	63.15507	0.
304.0	109986.0	44966.4	65.86580	0.
334.4	109986.0	44966.4	65.41323	0.
364.8	109986.0	44966.4	65.00897	0.
395.2	181244.0	74086.7	110.73939	29120.3
425.6	248157.0	102176.0	152.72515	28889.3
456.0	320747.0	132369.8	197.85672	30193.9
486.4	389506.0	160569.2	240.00703	28199.3
516.8	455971.0	187534.2	280.31247	26965.1
547.2	524750.0	216136.6	323.06514	28602.3
577.6	592296.0	243978.0	364.68045	27841.4
608.0	642679.0	263986.7	394.58798	20008.7
638.4	699283.0	286760.4	428.62843	22773.7
668.8	765458.0	313687.4	468.87698	26927.0
699.2	765458.0	313687.4	464.72252	0.
729.6	765458.0	313687.4	461.24623	0.
760.0	765458.0	313687.4	458.13374	0.
790.4	772761.0	313687.4	460.14814	0.
820.8	772761.0	313687.4	457.39419	0.
851.2	772761.0	313687.4	454.84088	0.
881.6	797803.0	313857.5	469.13127	170.1
912.0	820010.0	322740.1	482.40829	8882.6
942.4	832676.0	326928.3	488.66856	4188.2
972.8	844594.0	330809.8	494.47032	3881.5
1003.2	863129.0	337948.1	505.14008	7138.3
1033.6	869093.0	338928.3	506.60523	980.2
1064.0	873236.0	339127.3	506.90277	199.1
1094.4	884727.0	343359.6	513.22877	4232.2
1124.8	895727.0	347314.6	519.14040	3955.0
1155.2	911980.0	354106.5	529.29245	6791.9
1185.6	921876.0	357429.8	534.25990	3323.3
1216.0	926186.0	357791.4	534.80045	361.6
1246.4	935901.0	361148.8	539.81884	3357.4
1276.8	951941.0	367922.6	549.94381	6773.8
1307.2	964375.0	372676.4	557.04946	4753.8
1337.6	977898.0	378022.8	565.04082	5346.4
1368.0	991909.0	383619.4	573.40628	5596.6

1398.4	1014630.0	393895.5	588.76622	10276.1
1428.8	1036543.0	403627.7	603.31317	9732.2
1459.2	1051791.0	409698.7	612.38767	6071.0
1489.6	1067894.0	416254.8	622.18721	6556.1
1520.0	1089093.0	425558.6	636.09389	9303.8
1550.4	1104809.0	431830.3	645.46835	6271.7
1580.8	1119656.0	437651.5	654.16951	5821.2
1611.2	1136246.0	444421.0	664.28798	6769.4
1641.6	1153284.0	451414.6	674.74147	6993.6
1672.0	1167486.0	456864.1	682.88699	5449.5
1702.4	1185257.0	464250.3	693.92744	7386.3
1732.8	1207810.0	474187.6	708.78093	9937.3
1763.2	1222816.0	479970.6	717.42499	5783.0
1793.6	1237318.0	485514.6	725.71177	5544.0
1824.0	1261226.0	496145.3	741.60174	10630.7
1854.4	1267541.0	497233.3	743.22793	1088.0
1884.8	1273118.0	498055.5	744.45692	822.2
1915.2	1282128.0	500798.5	748.55703	2743.0

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	36.00
volumetric heat capacity of adjacent formations(btu/cu ft-deg f)	41.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of adjacent formations(sq ft/day)	0.94
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	299.00
total pay thickness	348.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	Incremental oil (bbls)
30.4	1235.0	661.7	0.99277	661.7
60.8	16081.0	8602.6	12.90588	7940.8
91.2	39315.0	20844.3	31.27123	12241.7
121.6	50875.0	26656.1	39.99030	5811.8
152.0	67837.0	35336.4	53.01285	8680.4
182.4	76889.0	39695.9	59.55309	4359.5
212.8	86425.0	44330.7	66.50635	4634.8
243.2	95220.0	48553.9	72.84215	4223.2
273.6	108017.0	54903.2	82.36750	6349.3
304.0	117869.0	59620.4	89.44441	4717.2
334.4	128486.0	64737.3	97.12098	5116.9
364.8	143544.0	72197.7	108.31327	7460.4
395.2	153613.0	76916.6	115.39272	4718.9
425.6	162780.0	81154.7	121.75078	4238.1
456.0	172891.0	85897.1	128.86553	4742.4
486.4	183050.0	90646.3	135.99043	4749.2
516.8	197676.0	97764.3	146.66904	7118.0
547.2	209460.0	103293.8	154.96455	5529.5
577.6	218713.0	107450.0	161.19982	4156.2
608.0	228639.0	111974.9	167.98824	4524.9
638.4	236468.0	115365.2	173.07452	3390.3

668.8	246303.0	119842.6	179.79163	44.77.4
699.2	250277.0	121159.4	181.76718	1316.8
729.6	253247.0	121989.7	183.01279	830.3
760.0	257887.0	123754.2	185.65988	1764.5

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	37.00
volumetric heat capacity of adjacent formations(btu/cu ft-deg f)	41.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of adjacent formations(sq ft/day)	0.94
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	252.00
total pay thickness	312.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	16110.0	6337.3	10.11361	6337.3
60.8	79581.0	31159.7	49.72760	24822.4
91.2	134064.0	51927.1	82.87026	20767.4
121.6	137396.0	52312.1	83.48456	384.9
152.0	137396.0	52312.1	82.38710	0.
182.4	137396.0	52312.1	81.49178	0.
212.8	141199.0	52312.1	83.10507	0.
243.2	182896.0	68010.4	108.53741	15698.3
273.6	223860.0	83334.2	132.99257	15323.8
304.0	263749.0	98040.3	156.46197	14706.1
334.4	304594.0	112976.7	180.29890	14936.4
364.8	339727.0	125530.7	200.33386	12554.1
395.2	384330.0	141743.2	226.20728	16212.5
425.6	384330.0	141743.2	223.82423	0.
456.0	440595.0	161166.1	257.20422	19422.9
486.4	491429.0	179579.4	286.58984	18413.2
516.8	531057.0	193411.4	308.66424	131332.0
547.2	572258.0	207815.6	331.65189	14404.2
577.6	626150.0	227131.4	362.47785	19315.8
608.0	674611.0	244626.6	390.39829	17495.2
638.4	713227.0	258033.2	411.79388	13406.6
668.8	742953.0	267829.4	427.42762	9796.2
699.2	785573.0	282897.8	451.47515	15068.4
729.6	842972.0	303844.5	484.90387	20'346.7
760.0	850456.0	304343.4	485.70008	498.9
790.4	850456.0	304343.4	482.14342	0.
820.8	850456.0	304343.4	478.94807	0.
851.2	860461.0	304343.4	482.46858	0.
881.6	869075.0	304343.4	485.13024	0.
912.0	869075.0	304343.4	482.30237	0.
942.4	893765.0	310572.7	495.64145	6229.3
972.8	914054.0	317583.9	506.83058	7011.2
1003.2	936131.0	325353.2	519.22943	7769.2
1033.6	967952.0	337385.6	538.43194	121632.4

1064.0	985968.0	343180.3	547.67972	5794.7
1094.4	986986.0	343180.3	545.00988	0.
1124.8	986986.0	343180.3	541.91848	0.
1155.2	1009179.0	348384.0	555.98421	5203.7
1185.6	1025771.0	354314.4	565.44855	5930.4
1216.0	1042452.0	360280.1	574.96923	5965.7
1246.4	1057943.0	365651.7	583.54173	5371.6
1276.8	1068467.0	368597.5	588.24281	2945.7
1307.2	1076812.0	370532.7	591.33115	1935.2
1337.6	1091687.0	375718.9	599.60779	5186.2
1368.0	1112480.0	383782.0	612.47569	8063.1
1398.4	1130582.0	390429.6	623.08458	6647.6
1428.8	1149341.0	397379.4	634.17582	6949.9
1459.2	1169624.0	405065.4	646.44187	7686.0
1489.6	1196458.0	415902.5	663.73664	10837.0
1520.0	1214756.0	422444.9	674.17762	6542.4
1550.4	1234297.0	429619.1	685.62699	7174.3
1580.8	1253899.0	436808.6	697.10057	7189.4
1611.2	1273501.0	443982.2	708.54894	7173.6
1641.6	1292048.0	450623.9	719.14838	6641.7
1672.0	1312693.0	458287.4	731.37848	7663.5
1702.4	1333267.0	465884.2	743.50217	7596.8
1732.8	1350323.0	471736.8	752.84234	5852.6
1763.2	1372450.0	480087.0	766.16843	8350.2
1793.6	1391600.0	486929.1	777.08759	6842.0
1824.0	1410211.0	493505.3	787.58259	6576.2
1854.4	1428004.0	499706.0	797.47826	6200.7
1884.8	1453833.0	509824.4	813.62608	10118.3
1915.2	1462800.0	511583.0	816.43272	1'758.7
1945.6	1469043.0	512139.8	817.32128	556.8
1976.0	1478742.0	514486.7	821.06669	2346.9

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	38.00
volumetric heat capacity of adjacent formations(btu/cu ft-deg f)	41.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of adjacent formations(sq ft/day)	0.94
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	220.00
total pay thickness	321.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	11640.0	3788.8	7.12581	3788.8
60.8	11640.0	3788.8	6.97075	0.
91.2	19850.0	6326.6	11.89886	2537.8
121.6	25491.0	8063.4	15.16524	1736.7
152.0	25491.0	8063.4	14.95519	0.
182.4	25491.0	8063.4	14.79506	0.
212.8	25491.0	8063.4	14.65884	0.

243.2	25491.Ø	8063.4	14.53834	0.
273.6	25491.0	8063.4	14.42933	0.
304.0	25491.0	8063.4	14.32924	0.
334.4	25491.0	8063.4	14.23635	0.
364.8	25491.0	8063.4	14.14944	0.
395.2	25491.0	8063.4	14.06759	0.
425.6	25491.0	8063.4	13.99011	0.
456.0	25491.0	8063.4	13.91644	0.
486.4	25491.0	8063.4	13.84615	0.
516.8	25491.0	8063.4	13.77886	0.
547.2	25491.0	8063.4	13.71428	0.
577.6	25491.0	8063.4	13.65215	0.
608.0	25491.0	8063.4	13.59225	0.
638.4	25491.0	8063.4	13.53439	0.
668.8	25491.0	8063.4	13.47841	0.
699.2	25491.0	8063.4	13.42417	0.
729.6	25491.0	8063.4	13.37154	0.
760.0	25491.Ø	8063.4	13.32041	0.
790.4	25491.0	8Ø63.4	13.27069	0.
820.8	32914.0	10026.9	18.85809	1'963.5
851.2	42010.0	13610.1	25.59732	3583.3
881.6	47790.0	15796.4	29.70916	2186.3
912.0	51974.0	17324.8	32.58372	1528.4
942.4	56494.0	18987.2	35.71033	1662.4
972.8	61181.0	20707.7	38.94617	1720.5
1003.2	65722.0	22358.4	42.05063	1650.6
1033.6	70131.Ø	23946.9	45.Ø3826	1588.5
1064.0	74583.0	25545.3	48.04450	1598.4
1094.4	79451.0	27304.0	51.35226	1758.7
1124.8	84508.0	29127.9	54.78247	1823.8
1155.2	89565.0	30940.3	58.1912Ø	1812.4
1185.6	94347.0	32631.4	61.37173	1691.1
1216.0	99717.0	34553.5	64.98678	1922.1
1246.4	105034.0	36441.8	68.53814	1888.3
1276.8	109445.0	37953.5	71.38136	1511.7
1307.2	115035.0	39941.1	75.11948	1987.6
1337.6	119856.0	41603.5	78.24597	1662.4
1368.0	124465.0	43176.0	81.20349	1572.5
1398.4	128535.0	44526.8	83.74409	1350.8
1428.8	133601.0	46280.9	87.84320	1754.1
1459.2	135814.0	46870.2	88.15138	589.2
1489.6	137359.0	47206.3	88.78348	336.1
1520.0	139776.0	47909.8	90.10658	703.5

RESERVOIR AND STEAM PROPERTIES

volumetrfc heat capacity of reservoir(btu/cu ft-deg f)	38.00
volumetric heat capacity of adjacent formations(btu/cu ft-deg f)	41.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusfvity of adjacent formations(sq ft/day)	0.94
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	235.00
total pay thickness	299.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	12972.0	5991.3	9.82602	5991.3
60.8	34071.0	15620.2	25.61777	9628.9
91.2	61353.0	27909.8	45.77307	12289.5
121.6	78690.0	35424.6	58.09762	7514.8
152.0	91212.0	40674.0	66.70682	5249.4
182.4	108646.0	48185.6	79.0261 6	7511.6
212.8	124098.0	54706.1	89.72005	652Ø.5
243.2	136594.0	59825.3	98.11563	5119.1
273.6	149713.0	65227.0	106.97461	5401.7
304.0	163657.0	70986.5	116.42040	5759.5
334.4	178843.0	77287.5	126.75435	63Ø1.Ø
364.8	193653.0	83370.5	136.73068	6083.0
395.2	208463.0	89420.0	146.65209	6Ø49.5
425.6	222477.0	95068.8	155.91626	5648.8
456.0	238222.0	101497.1	166.45903	6428.4
486.4	253953.0	107876.4	176.92125	6379.3
516.8	266943.0	112950.7	185.24325	5B74.3
547.2	283541.0	119692.7	196.30041	6'742.0
577.6	304663.0	128472.4	210.69942	8'779.7
608.0	317938.0	133532.1	218.99747	5Ø59.7
638.4	330014.0	138056.8	226.41816	4524.7
668.8	345131.0	143999.7	236.16483	5'343.0
699.2	351694.0	145947.5	239.35932	1'347.8
729.6	356294.0	147052.9	241.17208	1105.3
760.0	363387.0	149368.4	244.96962	2315.5

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	37.00
volumetric heat capacity of adjacent formations(btu/cu ft-deg f)	41.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of adjacent formations(sq ft/day)	0.94
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	245.00
total pay thickness	305.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	14646.0	5726.2	9.18863	5726.2
60.8	70914.0	27591.2	44.27456	21865.0
91.2	116719.0	44898.9	72.04768	17307.8
121.6	194879.0	74645.2	119.78037	29746.2
152.0	253591.0	96304.4	154.53609	21659.2
182.4	305716.0	115216.3	184.88337	18911.9
212.8	365169.0	137522.2	220.67680	22305.9
243.2	420526.0	157974.8	253.49639	20452.6

273.6	511338.0	192573.8	309.01613	34599.0
304.0	590488.0	222005.7	356.24452	29432.0
334.4	635039.0	237272.0	380.74169	15266.2
364.8	647154.0	239580.5	384.44602	2308.5
395.2	647154.0	239580.5	380.81714	0.
425.6	647154.0	239580.5	377.64106	0.
456.0	661354.0	239580.5	383.94254	0.
486.4	674942.0	242954.2	389.85978	3373.8
516.8	674942.0	242954.2	387.04950	0.
547.2	707637.0	252780.6	405.62781	9826.4
577.6	738251.0	264269.5	424.06367	11488.9
608.0	765371.0	274126.4	439.88058	9856.8
638.4	792223.0	283826.3	455.44575	9700.0
668.8	821900.0	294730.3	472.94289	10903.9
699.2	821900.0	294730.3	469.40517	0.
729.6	821900.0	294730.3	466.27424	0.
760.0	860599.0	307343.3	493.18265	12613.1
790.4	891014.0	319776.6	513.13377	12433.2
820.8	921631.0	332221.6	533.10392	12445.1
851.2	944198.0	340662.8	546.64915	8441.2
881.6	956864.0	344353.1	552.57087	3690.3
912.0	977988.0	352249.7	565.24220	7896.6
942.4	1001361.0	361199.3	579.60336	8949.6
972.8	1019538.0	367585.8	589.85154	6386.5
1003.2	1041713.0	375936.8	603.25213	8351.0
1033.6	1061004.0	382828.3	614.31058	6891.4
1064.0	1079301.0	389248.1	624.61223	6419.8
1094.4	1101412.0	397554.4	637.94103	8306.3
1124.8	1120048.0	404107.0	648.45573	6552.6
1155.2	1140219.0	411420.2	660.19100	7313.2
1185.6	1166074.0	421497.7	676.36205	10077.5
1216.0	1186220.0	428701.2	687.92118	7203.5
1246.4	1205094.0	435300.5	698.51091	6599.3
1276.8	1226482.0	443133.5	711.08024	7833.0
1307.2	1247600.0	450809.0	723.39679	7675.5
1337.6	1276662.0	462343.8	741.90618	11534.8
1368.0	1301093.0	471523.7	756.63681	9179.9
1398.4	1326627.0	481216.0	772.18982	9692.4
1428.8	1344750.0	487242.0	781.85954	6026.0
1459.2	1360933.0	492377.7	790.10853	5135.6
1489.6	1381169.0	499527.4	801.57332	7149.7
1520.0	1395706.0	503887.0	808.56904	4359.6
1550.4	1407229.0	506835.5	813.30038	2948.5
1580.8	1416739.0	508870.8	816.56636	2035.3

APPENDIX B. VOGEL COMPUTER PROGRAM

This appendix contains a program listing of Vogel4.f, the computer program written to perform the Vogel overlay steamflood calculation. As commented in the program, the month-by-month injection rates may be printed out via a slight modification of the program. This was not done so in this version because of the great length of the data.

Following the program listing is a sample output for this model.

B.1 Program Listing

```
****************************************************************************
****************************************************************************
**********                         VOGEL4.F                         **********
**********   A COMPUTER PROGRAM THAT PERFORMS OIL PRODUCTION        **********
**********   PREDICTION BASED ON VOGEL'S STEAM OVERLAY MODEL        **********
****************************************************************************
****************************************************************************
C First, the necessary arrays are dimensioned, and storage files opened.
      implicit real*8(a-h,o-z)
      real*8 lv(72),mr
      dimension qr(72), wi(72),cw(72),ts(72),fs(72),lv(72),hpr(72)
      dimension td(72),time(72),delqr(72),delwi(72),tint(72),wib(72)
      dimension win(1Ø,72),ll(72),q(72),pop(1Ø,72),nip(1Ø),totoil(72)
      dimension steam(1Ø,72),prodoil(1Ø,72),stinj(1Ø,72)
      dimension totsteam(72),dts(72),delt(72)
      open(unit=3,file='vogresult')
      rewind(unit=3)
      open(unit=4,file='grap')
      rewind(unit=4)
C This begins the interactive part of the program, in which the user is
C requested all the necessary reservoir properties, thermal and non-thermal.
C This data may be easily input with a file as well.
      write(6,15)
   15 format('number of segments')
C The variable kseg and its accompanying do loop allow for running all six
C well groupings at the same time.  Kseg is simply the number of well
C groupings utilized per run.
      read(5,*) kseg
      pi=3.1415927
      do 17 l15=1,kseg
      do 18 m=1,72
      qr(m)=Ø.Ø
      wi(m)=Ø.Ø
      cw(m)=Ø.Ø
      ts(m)=Ø.Ø
      fs(m)=Ø.Ø
      lv(m)=Ø.Ø
      hpr(m)=Ø.Ø
      td(m)=Ø.Ø
      time(m)=Ø.Ø
      delqr(m)=Ø.Ø
      delwi(m)=Ø.Ø
      tint(m)=Ø.Ø
      wib(m)=Ø.Ø
      ll(m)=Ø.Ø
      q(m)=Ø.Ø
      dts(m)=Ø.Ø
      delt(m)=Ø.Ø
   18 continue
      opold=Ø.Ø
      qold=Ø.Ø
      vsold=Ø.Ø
      write(6,2Ø)
   20 format('capture efficiency(fraction)?')
      read(5,*) ec
      write(6,21)
   21 format('formation volume factor?')
      read(5,*) bo
      write(6,22)
   22 format('initial oil saturation(fraction)?')
      read(5,*) soi
      write(6,23)
   23 format('residual oil saturation(fraction)?')
      read(5,*) sor
```

```
      write(6,24)
   24 format('net pay thickness(ft)?')
      read(5,*) hn
      write(6,25)
   25 format('total pay thickness(ft)?')
      read(5,*) ht
      write(6,80)
   80 format('area of steam overlay(acres)')
      read(5,*) a
      a=43560.0*a
      write(6,26)
   26 format('porosity of the reservoir(fraction)?')
      read(5,*) porpay
      write(6,27)
   27 format('temperature of undisturbed reservoir(deg f)?')
      read(5,*) tr
      write(6,28)
   28 format('thermal diffusivity of overburden(sq ft/day)?')
      read(5,*) alphab
      write(6,47)
   47 format('thermal diffusivity of res below(sq ft/day)?')
      read(5,*) alphar
      write(6,70)
   70 format('thermal conductivity of overburden(btu/ft-d-deg f)')
      read(5,*) tkb
      write(6,71)
   71 format('thermal conductivity of res below(btu/ft-d-deg f)')
      read(5,*) tkr
      write(6,30)
   30 format('number of time intervals?')
      read(5,*) ni
      nip(115)=ni
      write(6,31)
   31 format('size of time step(days)?')
      read(5,*) tstep
      write(6,32)
   32 format('volumetric injection rate per interval(bbl/day), enthalpy
     *code?')
      do 33 j=1,ni
      read(5,*) win(115,j),ll(j)
      wib(j)=win(115,j)/30.4
      wi(j)=wib(j)*350.376
   33 continue
C The following loops contain codes which trigger the correct enthalpy
C content and downhole temperature for each month's injection rate.
      do 38 j=1,ni
      if(ll(j).eq.1) then
      q(j)=890.0
      ts(j)=316.0
      dts(j)=ts(j)-tr
      end if
      if(ll(j).eq.2) then
      q(j)=906.0
      ts(j)=321.0
      dts(j)=ts(j)-tr
      end if
      if(ll(j).eq.3) then
      q(j)=905.0
      ts(j)=346.0
      dts(j)=ts(j)-tr
      endif
      if(ll(j).eq.4) then
      q(j)=909.0
      ts(j)=372.0
```

```
      dts(j)=ts(j)-tr
      end if
      if(ll(j).eq.5) then
      q(j)=912.Ø
      ts(j)=382.Ø
      dts(j)=ts(j)-tr
      end if
      if(ll(j).eq.6) then
      q(j)=9Ø8.Ø
      ts(j)=367.Ø
      dts(j)=ts(j)-tr
      end if
   38 continue
      write(6,42)
   42 format('fraction of heat injected that is produced per interval?')
      read(5,*) hpr(1)
      do 43 j=1,ni
      hpr(j)=hpr(1)
   43 continue
      write(6,44)
   44 format('length of time of each interval(days)?')
      read(5,*) tint(1)
      do 45 j=1,ni
      tint(j)=tint(1)
   45 continue
      write(6,46)
   46 format('volumetric heat capacity of reservoir(btu/cu ft deg f)?')
      read(5,*) mr
      b=a/4356Ø.Ø
C The input parameters are next printed out on both the screen and in the
C results file in order to double check them.
      write(6,5Ø) mr,b,tr,alphab,alphar,tkb,tkr,porpay,soi,sor,
     *hn,ht,bo,eb
      write(3,5Ø) mr,b,tr,alphab,alphar,tkb,tkr,porpay,soi,sor,
     *hn,ht,bo,ec
   50 format(25x,'RESERVOIR AND STEAM PROPERTIES',//,
     *'volumetric heat capacity of reservoir(btu/cu ft-deg f)',t67,f12.2
     *,/,
     *'area of steam overlay(acres)',t67,f12.2,/,
     *'temperature of undisturbed reservoir(deg f)',t67,f12.2,/,
     *'thermal diffusivity of overburden(sq ft/day)',t67,f12.2,/,
     *'thermal diffusivity of res below(sq ft/day)',t67,f12.2,/,
     *'thermal conductivity of overurden(btu/ft-d-deg f)',t67,f12.2,/,
     *'thermal conductivity of res below(btu/ft-d-deg f)',t67,f12.2,/,
     *'porosity',t67,f12.2,/,
     *'initial oil saturation',t67,f12.2,/,'residual oil saturation',t67
     *,f12.2,/,'net pay thickness(ft)',t67,f12.2,/,
     *'total pay thickness',t67,f12.2,/,
     *'oil formation volume factor',t67,f12.2,/,
     *'capture efficiency',t67,f12.2,//)
C Input parameters that vary from month to month may also be printed
C out.  Here, however, that step has been bypassed because of the
C lengthiness of the data. Removal of the 'go to 60' satement will
C implement this printed output.
      go to 60
      do 60 i=1,ni
      write(6,51) i,tint(i),wib(i),fs(i),lv(i),cw(i),ts(i),hpr(i)
      write(3,51) i,tint(i),wib(i),fs(i),lv(i),cw(i),ts(i),hpr(i)
   51 format(25x,'INTERVAL # ',i2,/,'time(days)',t6Ø,f12.2,/,
     *'injection rate(bbls/day)',t6Ø,f12.2,/,'quality of steam',
     *t6Ø,f12.2,/,'latent heat of vaporization(btu/lb)',t6Ø,f12.2,
     */,'heat capacity of steam(btu/lb-deg f)',t6Ø,f12.2,/,
     *'temperature of steam(deg f)',t6Ø,f12.2,/,
     *'fraction of injected heat produced',t6Ø,f12.2,//)
```

```
   60 continue
C The downhole heat injected is calculated for each month in the following
C step.
      do 100 i=1,ni
      qr(i)=wi(i)*q(i)
  100 continue
      tcum=Ø.Ø
C In this loop, cumulative time at the end of each month is calculated and
C stored.
      do 200 i=1,ni
      tcum=tcum+tint(i)
      time(i)=tcum
  200 continue
C The following steps compute change in heat input rate, water injection
C rate, and difference between ambient and steam temperature over each
C monthly time step.
      delqr(1)=qr(1)
      delwi(1)=wi(1)
      delt(1)=dts(1)
      if (ni.eq.1) go to 300
      do 300 i=1,ni-1
      delqr(i+1)=qr(i+1)-qr(i)
      delwi(i+1)=wi(i+1)-wi(i)
      delt(i+1)=dts(i+1)-dts(i)
  300 continue
C The headings for the output tables are printed here.
      write(3,35Ø)
      write(6,35Ø)
  358 format('time(days)',5x,'cum steam injected',5x,
     *'cum oil produced',5x,'size of steam zone',5x,'incremental oil')
      write(3,351)
      write(6,351)
  351 format(15x,'(bbls water equiv)',11x,'(bbls)',12x,'(acre-ft)',
     *12x,'(bbls)',//)
C This begins the critical calculation of the Vogel model.  Each proceeding
C time step is checked to see if it has just passed a predetermined
C downhole temperature change point.  If it has, a superposition
C calculation is performed.  If not, a standard heat loss calculation
C is performed.
      tt=tstep
      mm=1
  390 do 400 i=1,ni
      l=ni+1-i
      j=1
      if(tt.gt.time(l)) go to 450
C The following is the standard heat loss calculation.
  400 continue
      qcum=delqr(1)*tt
      wcum=delwi(1)*tt
      qlost=2.Ø*tkr*a*delt(1)*(tt/(pi*alphar))**Ø.5+2.Ø*tkb*a*delt(1)*
     *(tt/(pi*alphab))**Ø.5
      qtot=qcum-qlost
      temp=ts(1)
      go to 7ØØ
C The following is the superposition heat loss calculation.
  450 qcum=delqr(1)*tt
      wcum=delwi(1)*tt
      qlost=2.Ø*tkr*a*delt(1)*(tt/(pi*alphar))**Ø.5+2.Ø*tkb*a*delt(1)*
     *(tt/(pi*alphab))**Ø.5
      do 600 i=1,j
      dtime=tt-time(i)
      qcum=qcum+delqr(i+1)*dtime
      wcum=wcum+delwi(i+1)*dtime
      qlost=qlost+2.*tkr*a*delt(i+1)*(dtime/(pi*alphar))**.5+
```

```
     *2.*tkb*a*delt(i+1)*(dtime/(pi*alphab))**.5
  600 continue
C The total cumulative heat remaining in the reservoir is then the total
C injected, qtot, less the total lost, qlost.
      qtot=qcum-qlost
      temp=ts(j+1)
C If this total falls below zero, it is reset to zero to insure that a
C negative steam zone does not arise.
  700 if(qtot.le.0.0) qtot=Ø.Ø
C Incremental heat is calculated by subtraction, followed by the incremental
C steam zone qrowth of that month.  These are qinc and vsinc, respectively.
      qinc=qtot-qold
      write(6,7Ø1) qlost
  701 format(el3.5)
      vsinc=qinc/(mr*(temp-tr))*(1.Ø/4356Ø.Ø)
      vs=vsinc+vsold
C A second check to make sure a negative steam zone has not arisen is done
C here.
      if(vs.lt.0.0) vs=Ø.Ø
      if(qtot.le.0.0) vs=Ø.Ø
      if(vs.le.0.0) qtot=Ø.Ø
      vw=wcum/35Ø.376
C Cumulative produced oil is calculated now, with a check to make sure It
C does not exceed last month's cumulative total.  If it does, it is set back
C to last month's total.
      op=7758.Ø*porpay*(hn/ht)*(soi-sor)*ec*vs/bo
      if(op.lt.opold) op=opold
      pop(115,mm)=op
      steam(115,mm)=vw
      difop=op-opold
C Results are now output.
      write(3,75Ø) tt,vw,op,vs,difop
      write(6,75Ø) tt,vw,op,vs,difop
  750 format(2x,f6.1,1Øx,f1Ø.1,11x,f9.1,14x,f9.2,11x,f9.1)
C Old values for oil produced, steam zone volume, and heat in the reservoir
C are now reset.
      opold=op
      vsold=vs
      qold=qtot
      tt=tt+tstep
      mm=mm+1
C Once the number of time steps exceeds the previously input maximum, the
C program goes on to the next well grouping.  If not, it returns to the
C beginning of the loop with the new time level and starts the calculation
C again.
      if(tt.le.time(ni)) go to 390
   17 continue
C This part of the program adds the results of all of the well groupings
C and prepares them for an input file to automatically graph them.
      do 800 k=1,kseg
      mn=72-nip(k)
      do 810 j=1,mn
      prodoil(k,j)=Ø.Ø
      stinj(k,j)=Ø.Ø
  810 continue
      do 820 j=1,nip(k)
      mmn=mn+j
      prodoil(k,mmn)=pop(k,j)
      stinj(k,mmn)=steam(k,j)
  820 continue
  800 continue
      do 900 n=1,72
      do 910 k=1,kseg
      totoil(n)=totoil(n)+prodoil(k,n)
```

```
     totsteam(n)=totsteam(n)+stinj(k,n)
910  continue
900  continue
     jk1=29
     write(4,920) jkl
920  format(i5)
     do 940 j=44,72
     write(4.930) totsteam(j),totoil(j)
930  format(2f13.4)
940  continue
     stop
     end
```

B.2 Sample Output

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	36.00
area of steam overlay(acres)	9.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of overburden(sq ft/day)	0.94
thermal diffusivity of res below(sq ft/day)	0.86
thermal conductivity of overurden(btu/ft-d-deg f)	39.00
thermal conductivity of res below(btu/ft-d-deg f)	32.00
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	307.00
total pay thickness	356.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	5840.0	0.	0.	0.
60.8	57636.0	0.	0.	0.
91.2	105152.0	0.	0.	0.
121.6	105152.0	0.	0.	0.
152.0	105152.0	0.	0.	0.
182.4	105152.0	0.	0.	0.
212.8	105152.0	0.	0.	0.
243.2	105152.0	0.	0.	0.
273.6	105152.0	0.	0.	0.
304.0	109986.0	0.	0.	0.
334.4	109986.0	0.	0.	0.
364.8	109986.0	0.	0.	0.
395.2	181244.0	0.	0.	0.
425.6	248157.0	0.	0.	0.
456.0	320747.0	0.	0.	0.
486.4	389506.0	0.	0.	0.
516.8	455971.0	0.	0.	0.
547.2	524750.0	0.	0.	0.
577.6	592296.0	0.	0.	0.
608.0	642679.0	0.	0.	0.
638.4	699283.0	0.	0.	0.
668.8	765458.0	0.	0.	0.
699.2	765458.0	0.	0.	0.
729.6	765458.0	0.	0.	0.
760.0	765458.0	0.	0.	0.
790.4	772761.0	0.	0.	0.
820.8	772761.0	0.	0.	0.
851.2	772761.0	0.	0.	0.
881.6	797803.0	0.	0.	0.
912.0	820810.0	0.	0.	0.
942.4	832676.0	0.	0.	0.
972.8	844594.0	0.	0.	0.
1003.2	863129.0	0.	0.	0.
1033.6	869093.0	0.	0.	0.
1064.0	873236.0	0.	0.	0.
1094.4	884727.0	0.	0.	0.
1124.8	895727.0	0.	0.	0.
1155.2	911980.0	0.	0.	0.
1185.6	921876.0	0.	0.	0.

1216.0	926186.0	0.	0.	0.
1246.4	935901.0	0.	0.	0.
1276.8	951941.0	0.	0.	0.
1307.2	964375.0	0.	0.	0.
1337.6	977898.0	0.	0.	0.
1368.0	991909.0	0.	0.	0.
1398.4	1014630.0	0.	0.	0.
1428.8	1036543.0	0.	0.	0.
1459.2	1051791.0	0.	0.	0.
1489.6	1067894.0	0.	0.	0.
1520.0	1089093.0	5168.5	7.73	5168.5
1550.4	1104809.0	10340.9	15.46	5172.5
1580.8	1119656.0	14225.2	21.26	3884.3
1611.2	1136246.0	18989.0	28.38	4763.8
1641.6	1153284.0	23970.9	35.83	4981.9
1672.0	1167486.0	27377.1	40.92	3406.2
1702.4	1185257.0	32753.0	48.96	5375.9
1732.8	1207810.0	39252.1	58.67	6499.1
1763.2	1222816.0	44059.4	65.86	4807.3
1793.6	1237318.0	47811.9	71.47	3752.4
1824.0	1261226.0	55169.3	82.46	7357.4
1854.4	1267541.0	55169.3	80.34	0.
1884.8	1273118.0	55169.3	77.85	0.
1915.2	1282128.0	55169.3	78.31	0.

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	36.00
area of steam overlay(acres)	4.50
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of overburden(sq ft/day)	0.94
thermal diffusivity of res below(sq ft/day)	0.86
thermal conductivity of overurden(btu/ft-d-deg f)	39.00
thermal conductivity of res below(btu/ft-d-deg f)	32.00
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	299.00
total pay thickness	348.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone {acre-ft)	incremental oil (bbls)
30.4	1235.0	0.	0.	0.
60.8	16081.0	0.	0.	0.
91.2	39315.0	0.	0.	0.
121.6	50875.0	0.	0.	0.
152.0	67837.0	0.	0.	0.
182.4	76889.0	0.	0.	0.
212.8	86425.0	0.	0.	0.
243.2	95220.0	0.	0.	0.
273.6	108017.0	0.	0.	0.

304.0	117869.0	0.	0.	0.
334.4	128486.0	0.	0.	0.
364.8	143544.0	0.	0.	0.
395.2	153613.0	0.	0.	0.
425.6	162780.0	0.	0.	0.
456.0	172891.0	0.	0.	0.
486.4	183050.0	0.	0.	0.
516.8	197676.0	0.	0.	0.
547.2	209460.0	0.	0.	0.
577.6	218713.0	0.	0.	0.
608.0	228639.0	0.	0.	0.
638.4	236468.0	0.	0.	0.
668.8	246303.0	0.	0.	0.
699.2	250277.0	0.	0.	0.
729.6	253247.0	0.	0.	0.
760.0	257887.0	0.	0.	0.

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	37.00
area of steam overlay(acres)	9.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of overburden(sq ft/day)	0.94
thermal diffusivity of res below(sq ft/day)	0.87
thermal conductivity of overurden(btu/ft-d-deg f)	39.00
thermal conductivity of res below(btu/ft-d-deg f)	32.00
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	252.00
total pay thickness	312.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	16110.0	0.	0.	0.
60.8	79581.0	0.	0.	0.
91.2	134064.0	0.	0.	0.
121.6	137396.0	0.	0.	0.
152.0	137396.0	0.	0.	0.
182.4	137396.0	0.	0.	0.
212.8	141199.0	0.	0.	0.
243.2	182896.0	0.	0.	0.
273.6	223860.0	0.	0.	0.
304.0	263749.0	0.	0.	0.
334.4	304594.0	0.	0.	0.
364.8	339727.0	0.	0.	0.
395.2	384330.0	0.	0.	0.
425.6	384330.0	0.	0.	0.
456.0	440595.0	0.	0.	0.
486.4	491429.0	0.	0.	0.
516.8	531057.0	0.	0.	0.

547.2	572258.0	0.	0.	0.
577.6	626150.0	0.	0.	0.
608.0	674611.0	0.	0.	0.
638.4	713227.0	0.	0.	0.
668.8	742953.0	0.	0.	0.
699.2	785573.0	0.	0.	0.
729.6	842972.0	0.	0.	0.
760.0	850456.0	0.	0.	0.
790.4	850456.0	0.	0.	0.
820.8	850456.0	0.	0.	0.
851.2	860461.0	0.	0.	0.
881.6	869075.0	0.	0.	0.
912.0	869075.0	0.	0.	0.
942.4	893765.0	0.	0.	0.
972.8	914054.0	0.	0.	0.
1003.2	936131.0	0.	0.	0.
1033.6	967952.0	0.	0.	0.
1064.0	985968.0	1480.9	2.36	1480.9
1094.4	986986.0	1480.9	0.	0.
1124.8	986986.0	1480.9	0.	0.
1155.2	1009179.0	5764.7	9.20	4283.8
1185.6	1025771.0	12224.9	19.51	6460.3
1216.0	1042452.0	17881.4	28.54	5656.5
1246.4	1057943.0	22510.8	35.92	4629.4
1276.8	1068467.0	24379.1	38.91	1868.3
1307.2	1076812.0	24975.6	39.86	596.6
1337.6	1091687.0	28733.8	45.86	3758.1
1368.0	1112480.0	33992.2	54.25	5258.5
1398.4	1130582.0	40078.7	63.96	6086.5
1428.8	1149341.0	45730.2	72.98	5651.5
1459.2	1169624.0	50660.0	80.85	4929.8
1489.6	1196458.0	59667.9	95.22	9008.0
1520.0	1214756.0	65903.6	105.18	6235.7
1550.4	1234297.0	71960.0	114.84	6056.4
1580.8	1253899.0	77941.6	124.39	5981.6
1611.2	1273501.0	83878.0	133.86	5936.4
1641.6	1292048.0	89261.2	142.45	5383.2
1672.0	1312693.0	95689.0	152.71	6427.8
1702.4	1333267.0	102077.4	162.90	6388.4
1732.8	1350323.0	106697.1	170.28	4619.7
1763.2	1372450.0	113872.4	181.73	7175.2
1793.6	1391600.0	119557.1	190.80	5684.8
1824.0	1410211.0	124979.8	199.45	5422.7
1854.4	1428004.0	128620.4	205.26	3640.6
1884.8	1453833.0	137145.9	218.87	8525.5
1915.2	1462800.0	138753.2	221.44	1607.2
1945.6	1469043.0	138753.2	220.58	0.
1976.0	1478742.0	139340.9	222.37	587.7

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	38.00
area of steam overlay(acres)	2.25
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of overburden(sq ft/day)	0.94
thermal diffusfvity of res below(sq ft/day)	0.87

thermal conductivity of overurden(btu/ft-d-deg f)	39.00
thermal conductivity of res below(btu/ft-d-deg f)	33.00
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	220.00
total pay thickness	321.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	11640.0	0.	0.	0.
60.8	11640.0	0.	0.	0.
91.2	19850.0	0.	0.	0.
121.6	25491.0	0.	0.	0.
152.0	25491.0	0.	0.	0.
182.4	25491.0	0.	0.	0.
212.8	25491.0	0.	0.	0.
243.2	25491.0	0.	0.	0.
273.6	25491.0	0.	0.	0.
304.0	25491.0	0.	0.	0.
334.4	25491.0	0.	0.	0.
364.8	25491.0	0.	0.	0.
395.2	25491.0	0.	0.	0.
425.6	25491.0	0.	0.	0.
456.0	25491.0	0.	0.	0.
486.4	25491.0	0.	0.	0.
516.8	25491.0	0.	0.	0.
547.2	25491.0	0.	0.	0.
577.6	25491.0	0.	0.	0.
608.0	25491.0	0.	0.	0.
638.4	25491.0	0.	0.	0.
668.8	25491.0	0.	0.	0.
699.2	25491.0	0.	0.	0.
729.6	25491.0	0.	0.	0.
760.0	25491.0	0.	0.	0.
790.4	25491.0	0.	0.	0.
820.8	32914.0	0.	0.	0.
851.2	42010.0	0.	0.	0.
881.6	47790.0	0.	0.	0.
912.0	51974.0	0.	0.	0.
942.4	56494.0	0.	0.	0.
972.8	61181.0	0.	0.	0.
1003.2	65722.0	0.	0.	0.
1033.6	70131.0	0.	0.	0.
1064.0	74503.0	0.	0.	0.
1094.4	79451.0	0.	0.	0.
1124.8	84500.0	0.	0.	0.
1155.2	89565.0	0.	0.	0.
1185.6	94347.0	0.	0.	0.
1216.0	99717.0	0.	0.	0.
1246.4	105034.0	0.	0.	0.
1276.8	109445.0	0.	0.	0.
1307.2	115035.0	0.	0.	0.
1337.6	119856.0	0.	0.	0.
1368.0	124465.0	0.	0.	0.
1398.4	128535.0	0.	0.	0.
1428.8	133601.0	0.	0.	0.
1459.2	135814.0	0.	0.	0.
1489.6	137359.0	0.	0.	0.

1520.0	139776.0	O.	O.	O

RESERVOIR AND STEAM PROPERTIES

volumetrfc heat capacfty of reservoir(btu/cu ft-deg f)	38.OO
area of steam overlay(acres)	6.75
temperature of undisturbed reservoir(deg f)	75.00
thermal dfffusivfty of overburden(sq ft/day)	0.94
thermal diffusfvity of res below(sq ft/day)	0.87
thermal conductivity of overurden(btu/ft-d-deg f)	39.OO
thermal conductfvity of res below(btu/ft-d-deg f)	32.ØØ
porosity	0.25
initial oil saturation	0.50
residual oil saturatfon	O.10
net pay thickness(ft)	235.00
total pay thfckness	299.00
oil formatfon volume factor	1.OO
capture efficiency	1.OO

time(days)	cum steam fnjected (bbls water equiv)	cum of1 produced (bbls)	size of steam zone (acre-ft)	incremental of1 (bbls)
30.4	12972.0	O.	O.	O.
60.8	34071.0	O.	O.	O.
91.2	61353.0	O.	O.	O.
121.6	78690.0	O.	O.	O.
152.0	91212.0	Ø.	O.	O.
182.4	108646.0	O.	O.	O.
212.8	124098.0	O.	O.	O.
243.2	136594.0	O.	O.	O.
273.6	149713.0	Ø.	O.	O.
304.0	163657.0	O.	O.	O.
334.4	178843.0	O.	O.	O.
364.8	193653.0	O.	O.	O.
395.2	208463.0	O.	O.	O.
425.6	222477.0	O.	O.	O.
456.0	238222.Ø	O.	O.	O.
486.4	253953.0	O.	O.	O.
516.8	266943.0	O.	O.	O.
547.2	283541.0	O.	O.	O.
577.6	304663.0	O.	O.	O.
608.0	317938.0	O.	O.	O.
638.4	330014.0	O.	O.	O.
668.8	345131.0	O.	O.	O.
699.2	351694.0	O.	O.	O.
729.6	356294.0	O.	O.	O.
760.0	363387.0	O.	O.	O.

RESERVOIR AND STEAM PROPERTIES

volumetric heat capacity of reservoir(btu/cu ft-deg f)	37.00
area of steam overlay(acres)	9.00
temperature of undisturbed reservoir(deg f)	75.00
thermal diffusivity of overburden(sq ft/day)	0.94
thermal diffusivity of res below(sq ft/day)	0.87
thermal conductivity of overurden(btu/ft-d-deg f)	39.00
thermal conductivity of res below(btu/ft-d-deg f)	32.00
porosity	0.25
initial oil saturation	0.50
residual oil saturation	0.10
net pay thickness(ft)	245.00
total pay thickness	335.00
oil formation volume factor	1.00
capture efficiency	1.00

time(days)	cum steam injected (bbls water equiv)	cum oil produced (bbls)	size of steam zone (acre-ft)	incremental oil (bbls)
30.4	14646.0	0.	0.	0.
60.8	70914.0	0.	0.	0.
91.2	116719.0	0.	0.	0.
121.6	194879.0	0.	0.	0.
152.0	253591.0	0.	0.	0.
182.4	305716.0	0.	0.	0.
212.8	365169.0	0.	0.	0.
243.2	420526.0	0.	0.	0.
273.6	511338.0	0.	0.	0.
304.0	590488.0	18370.4	32.38	18370.4
334.4	635039.0	25485.0	44.92	7114.6
364.8	647154.0	25485.0	36.59	0.
395.2	647154.0	25485.0	20.84	0.
425.6	647154.0	25485.0	5.66	0.
456.0	661354.0	25485.0	0.45	0.
486.4	674942.0	25485.0	0.	0.
516.8	674942.0	25485.0	0.	0.
547.2	707637.0	25485.0	0.	0.
577.6	738251.0	25485.0	7.71	0.
608.0	765371.0	25485.0	17.97	0.
638.4	792223.0	25485.0	27.34	0.
668.8	821900.0	25485.0	38.53	0.
699.2	821900.0	25485.0	28.13	0.
729.6	821900.0	25405.0	17.75	0.
760.0	860599.0	27716.5	48.85	2231.5
790.4	891014.0	37848.0	66.71	10131.5
820.8	921631.0	47512.6	83.74	9664.7
851.2	944198.0	54531.3	96.11	7018.7
881.6	956864.0	54895.1	96.75	363.8
912.0	977988.0	59666.0	105.16	4770.9
942.4	1001361.0	65482.7	115.41	5816.7
972.8	1019538.0	68948.4	121.52	3465.7
1003.2	1041713.0	74243.2	130.85	5294.8
1033.6	1061004.0	79499.2	140.12	5256.0
1064.0	1079301.0	83548.0	147.25	4048.8
1094.4	1101412.0	87994.1	155.09	4446.1
1124.8	1120048.0	92838.3	163.63	4844.2
1155.2	1140219.8	97721.7	172.23	4883.4
1185.6	1166074.0	103891.7	183.11	6170.0
1216.0	1186220.0	109471.6	192.94	5579.9

1246.4	1205094.0	113827.2	200.62	4355.7
1276.8	1226482.0	119280.1	210.23	5452.9
1307.2	1247600.0	124605.0	219.62	5324.9
1337.6	1276662.0	132308.4	233.19	7703.4
1368.0	1301093.0	138687.0	244.44	6378.6
1398.4	1326627.0	145712.6	256.82	7025.6
1428.8	1344750.0	150717.0	265.64	5004.4
1459.2	1360933.0	154127.2	271.65	3410.2
1489.6	1381169.0	159311.6	280.79	5184.4
1520.0	1395706.0	161883.4	285.32	2571.8
1550.4	1407229.0	163085.0	287.44	1201.6
1580.8	1416739.0	163381.6	287.96	296.6

APPENDIX C. ECONOMIC ANALYSIS COMPUTER PROGRAM

This appendix contains a program listing of Econ1.f, the computer program written to perform the disounted cash flow analysis on the steamflood plus surfactant project.

Following the program listing is a sample output from this analysis. Note that this is the output referenced in section 2.3.4 of the main body of the report.

C.1 Program Listing

```
. . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .
******************************************************************************
**********                          ECON1.F                              **********
**********            A COMPUTER PROGRAM WHICH CALCULATES               **********
**********                   DISCOUNTED CASH FLOW                        **********
******************************************************************************
******************************************************************************
C First, the necessary arrays are dimensioned and output files opened.
      dimension op(4Ø),p(4Ø),tang(4Ø),untang(4Ø),oc(1Ø,4Ø),
      dimension op(4Ø),p(4Ø),tang(4Ø),untang(4Ø),oc(1Ø,4Ø),
     *wpt(4Ø),bp(4Ø),disc(4Ø),grev(4Ø),wirev(4Ø),advtax(4Ø),
     *wptax(4Ø),taxcredit(4Ø),opcost(4Ø),depreciation(4Ø,4Ø),alldep(4Ø)
     *,depletion1(4Ø),depletion(4Ø),salvage(4Ø),fit(4Ø),bfit(4Ø)
      dimension pwafit(4Ø),disc1(4Ø),tpwrev(1Ø),tpwopc(1Ø),tpwinv(1Ø),
     *tpwfit(1Ø),tpwbfit(1Ø),tpwafit(1Ø),pwadvtx(4Ø),tpwadvtx(1Ø),
     *afit(4Ø),pwrev(4Ø),pwopc(4Ø),pwinv(4Ø),pwfit(4Ø),pwbfit(4Ø),
     *pwwptax(4Ø),tpwwptax(1Ø),pwsalvage(4Ø),tpwsalvage(1Ø)
      open(unit=3,file='econres')
      rewind(unit=3)
      dep1=Ø.Ø
C This begins the interactive portion of the program in which all necessary
C inputs are entered.  Certain variable can be entered as either a quarterly
C schedule, or simply as a single figure with a quarterlv escalation rate.
      write(6,1Ø)
   10 format('number of quarters')
      read(5,*) np
      do 5 j=1,np-1
      salvage(j)=Ø.Ø
    5 continue
      write(6,11)
   11 format('oil production schedule(bbls)')
      do 12 i=1,np
      read(5,*)op(i)
   12 continue
      write(6,13)
   13 format('do you wish to enter Initial price, with',/,
     **escalation rate, or a schedule of prices?',/,
     *'Ø=initial only',/,'1=schedule')
      read(5,*) jj
      if(jj.eq.0) go to 16
      write(6,14)
   14 format('oil price($/bbl)')
      do 15 j=1,np
      read(5,*) p(j)
   15 continue
      go to 19
   16 write(6,17)
   17 format('oil price in first quarter($/bbl)')
      read(5,*) p(1)
      write(6,18)
   18 format('escalation rate of oil price, per quarter(%/quarter)')
      read(5,*) escp
      escp=escp/1ØØ.Ø
      do 19 j=1,np-1
      p(j+1)=p(j)*(1.Ø+escp)
   19 continue
      write(6,56)
   56 format('working interest(%)')
      read(5,*) wi
      wi=wi/1ØØ.Ø
      write(6,6Ø)
   60 format('any tangible investments?',/,'Ø=no',/,'1=yes')
      read(5,*) ijk
      if(ijk.eq.0) go to 24
```

```
   write(6,22)
22 format('how many quarters of tangible investment do you wish?')
   read(5,*) ntan
   write(6,23)
23 format('tangible investment($)')
   do 24 i=1,ntan
   read(5,*) tang(i)
   tang(i)=wi*tang(i)
24 continue
   write(6,65)
65 format('any intangible investments?',/,'Ø=no',/,'1=yes')
   read(5,*) kji
   if(kji.eq.0) go to 68
   write(6,66)
66 format('how many quarters of intangible invest. do you wish?')
   read(5,*) nintan
   write(6,67)
67 format('intangible investment($)')
   do 68 i=1,nintan
   read(5,*) untang(i)
   untang(i)=wi*untang(i)
68 continue
   write(6,25)
25 format('number of operating cost items')
   read(5,*) noc
   do 26 j=1,noc
   write(6,27) j
27 format('for operating cost item #',i2,', do you wish to',/,
  *'enter initial cost, with escalation rate, or an operating',/,
  *'cost schedule?',/,'Ø=initial only',/,'1=schedule')
   read(5,*) ii
   if(ii.eq.0) go to 30
   write(6,28)
28 format('operating cost($)')
   do 29 i=1,np
   read(5,*) oc(j,i)
   oc(j,i)=wi*oc(j,i)
29 continue
   go to 26
30 write(6,31)
31 format('operating cost in first quarter($)')
   read(5,*) oc(j,1)
   oc(j,1)=wi*oc(j,1)
   write(6,32)
32 format('operating cost escalation rate, per quarter(%/quarter)')
   read(5,*) esco
   esco=esco/1ØØ.Ø
   do 33 k=1,np-1
   oc(j,k+1)=oc(j,k)*(1.Ø+esco)
33 continue
26 continue
   write(6,34)
34 format('advalorem tax rate(%)')
   read(5,*) adv
   adv=adv/1ØØ.Ø
   write(6,35)
35 format('income tax rate(%)')
   read(5,*) tax
   tax=tax/1ØØ.Ø
   write(6,36)
36 format('investment tax credit rate(%)')
   read(5,*) credit
   credit=credit/1ØØ.Ø
   write(6.37)
```

```
   37 format('do you wish to enter a single wpt rate, or a',/,
     *'schedule of rates?',/,'Ø=single',/,'1=schedule')
      read(5,*) kk
      if(kk.eq.0) go to 40
      write(6,38)
   38 format('windfall profit tax rate')
      do 39 j=1,np
      read(5,*) wpt(j)
      wpt(j)=wpt(j)/1ØØ.Ø
   39 continue
      go to 42
   40 write(6,41)
   41 format('single windfall profit tax rate(%)')
      read(5,*) wpt(1)
      wpt(1)=wpt(1)/1ØØ.Ø
      do 42 j=1,np-1
      wpt(j+1)=wpt(j)
   42 continue
      write(6,43)
   43 format('do you wish to enter a single wpt base price,',/,
     *'with an escalation rate, or a schedule of base prices?',/,
     *'Ø=single price',/,'1=schedule of prices')
      read(5,*) ll
      if(ll.eq.Ø) go to 46
      write(6,44)
   44 format('base price($)')
      do 45 j=1,np
      read(5,*) bp(j)
   45 continue
      go to 49
   46 write(6,47)
   47 format('base price in first quarter($)')
      read(5,*) bp(1)
      write(6,48)
   48 format('base price escalation rate(%/quarter)')
      read(5,*) escb
      escb=escb/1ØØ.Ø
      do 49 j=1,np-1
      bp(j+1)=bp(j)*(1.Ø+escb)
   49 continue
      write(6,5Ø)
   50 format('number of discount rates to use')
      read(5,*) ndisc
      write(6,51)
   51 format('discount rate(%)')
      do 52 j=1,ndisc
      read(5,*) disc(j)
      disc(j)=disc(j)/1ØØ.Ø
   52 continue
      write(6,55)
   55 format('total royalty and override burden(%)')
      read(5,*) burd
      burd=burd/1ØØ.Ø
      write(6,9Ø)
   90 format('depletion allowance?',/,'Ø=no',/,'1=yes')
      read(5,*) ll
      if(ll.eq.1) depl=Ø.15
C This begins the calculation of the cash flow.
C First, gross revenue, being oil produced times price, is calculated.
      do 100 j=1,np
      grev(j)=p(j)*op(j)
C Working interest revenue takes into account royalty and override burdens.
      wirev(j)=grev(j)*(1.Ø-burd)*wi
C This is the ad valorem tax calculation.
```

```
      advtax(j)=wirev(j)*adv
C This is the windfall profit tax calculation.
      wptax(j)=(p(j)-bp(j))*wpt(j)*op(j)*(1.Ø-burd)*wi
C This is the investment tax credit calculation.
      taxcredit(j)=tang(j)*credit
C Here, all operating costs are merged into one quarterly figure.
      do 110 i=1,noc
      opcost(j)=opcost(j)+oc(i,j)
  110 continue
  100 continue
C The following calculates quarterly depreciation of tangible investments
C based on an ACRS depreciation schedule.
      do 120 j=1,ntan
      do 130 i=j,j+2Ø
      k=i-j+1
      if(k.le.20) dep=Ø.Ø525
      if(k.le.8) dep=Ø.Ø55
      if(k.le.4) dep=Ø.Ø375
      depreciation(i,j)=tang(j)*dep
  130 continue
  120 continue
C Total depreciation for the project is calculated here.
      do 140 i=1,np
      do 150 j=1,ntan
      alldep(i)=alldep(i)+depreciation(i,j)
  150 continue
  140 continue
C This is the depletion calculation.
      do 160 j=1,np
      depletion1(j)=wirev(j)*depl
      depletion(j)=.5*(wirev(j)-opcost(j)-advtax(j)-alldep(j)-untang(j)
     *)
      if(depletion1(j).le.depletion(j)) depletion(j)=depletion1(j)
      if(depletion(j).le.Ø.Ø) depletion(j)=Ø.Ø
  160 continue
C The following loop calculates the project's total production, gross revenue,
C working interest revenue, ad valorem tax, windfall profits tax, investment
C tax credit, operating cost, depletion allowance, depreciation, intangible
C expenditures, and tangible expenditures.
      do 200 j=1,np
      tprod=tprod+op(j)
      tgrev=tgrev+grev(j)
      twirev=twirev+wirev(j)
      tadvtax=tadvtax+advtax(j)
      twptax=twptax+wptax(j)
      ttaxcredit=ttaxcredit+taxcredit(j)
      topcost=topcost+opcost(j)
      tdepl=tdepl+depletion(j)
      tdeprec=tdeprec+alldep(j)
      tuntang=tuntang+untang(j)
      ttang=ttang+tang(j)
  200 continue
C Salvage value is calculated as that amount of tangible expenditures
C remaining undepreciated by project's end.
      salvage(np)=ttang-tdeprec
      tsalvage=salvage(np)
      do 210 j=1,np
C Finally, federal income tax is calculated and summed for the life of the
C project.
      fit(j)=(wirev(j)-advtax(j)-wptax(j)-opcost(j)-untang(j)
     *-alldep(j)-depletion(j))*tax
      tfit=tfit+fit(j)
  210 continue
      do 220 j=1,np
```

```
C BFIT cash flow is calculated.
      bfit(j)=wirev(j)-advtax(j)-wptax(j)-opcost(j)-untang(j)-tang(j)+
     *salvage(j)
      tbfit=tbfit+bfit(j)
C AFIT cash flow is calculated.
      afit(j)=bfit(j)-fit(j)+taxcredit(j)
      tafit=tafit+afit(j)
  220 continue
      write(6,400)
      write(3,400)
C The following lines arrange for printing out the resultant cash flow to
C and output filed.
  400 format('INCREMENTAL BBLS',5x,'PRICE($/bbl)',5x,'GROSS REV($)',
     *5x,'WI REV($)',5x,'OPERATING COST'./)
      do 410 j=1,np
      write(6,420) op(j),p(j),grev(j),wirev(j),opcost(j)
      write(3,420) op(j),p(j),grev(j),wirev(j),opcost(j)
  420 format(f12.2,5x,f12.2,5x,f12.2,5x,f12.2,5x,f12.2)
  410 continue
      write(6,425) tprod,tgrev,twirev,topcost
      write(3,425) tprod,tgrev,twirev,topcost
  425 format(/,f12.2,22x,f12.2,5x,f12.2,5x,f12.2,/)
      write(6,430)
      write(3,430)
  430 format('TANGIBLES($)',5x,'INTANGIBLES($)',5X,'AD VALOR TAX($)',5X,
     *'WINDFALL PROFITS TAX($)',/)
      do 440 j=1,np
      write(6,450) tang(j),untang(j),advtax(j),wptax(j)
      write(3,450) tang(j),untang(j),advtax(j),wptax(j)
  450 format(f12.2,5x,f12.2,5x,f12.2,10x,f12.2)
  440 continue
      write(6,455) ttang,tuntang,tadvtax,twptax
      write(3,455) ttang,tuntang,tadvtax,twptax
  455 format(/,f12.2,5x,f12.2,5x,f12.2,10x,f12.2,/)
      write(6,460)
      write(3,460)
  460 format('DEPRECIATION($)',5x,'DEPLETION($)',7x,'FIT($)',10x,
     *'ITC($)',7x,'SALVAGE VALUE($)',/)
      do 465 j=1,np
      write(6.470)alldep(j),depletion(j),fit(j),taxcredit(j),salvage(j)
      write(3,470)alldep(j),depletion(j),fit(j),taxcredit(j),salvage(j)
  470 format(f12.2,5x,f12.2,5x,f12 2,5x,f12.2,5x,f12.2)
  465 continue
      write(6,475)tdeprec,tdepl,tfit,ttaxcredit,tsalvage
      write(3,475)tdeprec,tdepl,tfit,ttaxcredit,tsalvage
  475 format(/,f12.2,5x,f12.2,5x,f12.2,5x,f12.2,5x,f12.2,/)
C This loop calculates the present worth, at input discount rates, for all
C of the various cash flow stages.
      do 300 i=1,ndisc
      do 230 j=1,np
      pwrev(j)=wirev(j)/((1.0+disc(i))**(j-0.5))
      tpwrev(i)=tpwrev(i)+pwrev(j)
      pwopc(j)=opcost(j)/((1.0+disc(i))**(j-0.5))
      tpwopc(i)=tpwopc(i)+pwopc(j)
      pwinv(j)=(tang(j)+untang(j))/((1.0+disc(i))**(j-1.0))
      tpwinv(i)=tpwinv(i)+pwinv(j)
      pwadvtx(j)=advtax(j)/((1.0+disc(i))**(j-0.5))
      tpwadvtx(i)=tpwadvtx(i)+pwadvtx(j)
      pwwptax(j)=wptax(j)/((1.0+disc(i))**(j-0.5))
      tpwwptax(i)=tpwwptax(i)+pwwptax(j)
      pwsalvage(j)=salvage(j)/((1.0+disc(i))**(j-0.5))
      tpwsalvage(i)=tpwsalvage(i)+pwsalvage(j)
      pwfit(j)=(fit(j)-taxcredit(j))/((1.0+disc(i))**(j-0.5))
      tpwfit(i)=tpwfit(i)+pwfit(j)
```

```
      pwbfit(j)=pwrev(j)-pwopc(j)-pwinv(j)-pwadvtx(j)-pwwptax(j)
     *+pwsalvage(j)
      tpwbfit(i)=tpwrev(i)-tpwopc(i)-tpwinv(i)-tpwadvtx(i)-tpwwptax(i)
     *+tpwsalvage(i)
      pwafit(j)=pwbfit(j)-pwfit(j)
      tpwafit(i)=tpwbfit(i)-tpwfit(i)
  230 continue
      discl(i)=100.0*disc(i)
      write(6,500) discl(i)
      write(3,500) discl(i)
C Here, all the present worth results are printed to an output file.
  500 format('DISCOUNT RATE IS ',f5.2,'% per quarter',//)
      write(6,510)
      write(3,510)
  510 format('PRESENT WORTH OF WI REV($)',5x,'PRESENT WORTH OF OP COST
     *($)',5x,'PRESENT WORTH OF INVESTMENTS($)',/)
      do 520 j=1,np
      write(6,530) pwrev(j),pwopc(j),pwinv(j)
      write(3,530) pwrev(j),pwopc(j),pwinv(j)
  530 format(f12.2,20x,f12.2,20x,f12.2)
  520 continue
      write(6,540) tpwrev(i),tpwopc(i),tpwinv(i)
      write(3,540) tpwrev(i),tpwopc(i),tpwinv(i)
  540 format(/,f12.2,20x,f12.2,20x,f12.2,/)
      write(6,550)
      write(3,550)
  550 format('PRESENT WORTH OF CASH FLOW BFIT($)',5x,'PRESENT WORTH OF C
     *ASH FLOW AFIT($)',/)
      do 555 j=1,np
      write(6,560) pwbfit(j),pwafit(j)
      write(3,560) pwbfit(j),pwafit(j)
  560 format(f12.2,30x,f12.2)
  555 continue
      write(6,570) tpwbfit(i),tpwafit(i)
      write(3,570) tpwbfit(i),tpwafit(i)
  570 format(/,f12.2,30x,f12.2,/)
  300 continue
 1000 stop
      end
```

C.2 Sample Output

INCREMENTAL BBLS	PRICE($/bbl)	GROSS REV($)	WI REV($)	OPERATING COST
20430.88	20.00	408600.00	408600.00	397861.00
69802.00	20.00	1396040.00	1396040.00	363678.00
66396.00	20.00	1327920.00	1327920.00	398533.00
78314.00	20.00	1566280.00	1566280.00	364361.00
66396.00	20.00	1327920.00	1327920.00	403125.00
78314.00	20.00	1566280.00	1566280.00	368963.00
66396.00	20.00	1327920.00	1327920.00	403838.00
78314.00	20.00	1566280.00	1566280.00	369686.00
66396.00	20.00	1327920.00	1327920.00	408706.00
78314.00	20.00	1566280.00	1566280.00	374565.00
66396.00	20.00	1327920.00	1327920.00	409462.00
78314.00	20.00	1566280.00	1566280.00	375334.00
813782.00		16275640.00	16275640.00	4638112.00

TANGIBLES($)	INTANGIBLES($)	AD VALOR TAX($)	WINDFALL PROFITS TAX($)
416800.00	0.	28602.00	9193.50
0.	0.	97722.80	31410.90
0.	0.	92954.40	29878.20
0.	0.	109639.60	35241.30
0.	0.	92954.40	29878.20
0.	0.	109639.60	35241.30
0.	0.	92954.40	29878.20
0.	0.	109639.60	35241.30
0.	0.	92954.40	29878.20
0.	0.	109639.60	35241.30
0.	0.	92954.40	29878.20
0.	0.	109639.60	35241.30
416800.00	0.	1139294.75	366201.91

DEPRECIATION($)	DEPLETION($)	FIT($)	ITC($)	SALVAGE VALUE($)
15630.00	0.	-21343.25	41680.00	0.
15630.00	209406.02	339096.19	0.	0.
15630.00	199188.02	295868.19	0.	0.
15630.00	234942.02	403233.06	0.	0.
22924.00	199188.02	289925.19	0.	0.
22924.00	234942.02	397285.06	0.	0.
22924.00	199188.02	289568.69	0.	0.
22924.00	234942.02	396923.56	0.	0.
21882.00	199188.02	287655.69	0.	0.
21882.00	234942.02	395005.06	0.	0.
21882.00	199188.02	287277.69	0.	0.
21882.00	234942.02	394620.56	0.	175055.98
241744.02	2380056.25	3755115.75	41680.00	175055.98

DISCOUNT RATE IS **2.50% per quarter**

PRESENT WORTH OF WI REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
403586.31	392979.09	416800.00
1345278.25	350454.19	0.
1248424.63	374674.97	0.
1436600.25	334193.81	0.
1188268.50	360730.13	0.
1367376.75	322108.09	0.
1131011.00	343955.41	0.
1301489.00	307187.91	0.

1076512.75	331328.09	0.
1238776.13	296244.72	0.
1024640.38	315946.22	0.
1179084.88	282548.88	0.
13941049.00	4012351.75	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-443524.50	-381274.56
870385.88	543619.69
758270.44	480114.28
969521.00	599673.50
717623.50	458188.47
918786.31	571952.81
682437.13	435806.78
873913.38	544092.63
645607.25	412411.72
827944.69	515533.88
613914.94	392247.75
919251.56	622183.88
8354131.50	5194550.50

DISCOUNT RATE IS 3.75% per quarter

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
401147.75	390604.59	416800.00
1321039.25	344139.81	0.
1211160.38	363491.31	0.
1376927.38	320312.22	0.
1125188.88	341580.66	0.
1279189.13	301334.03	0.
1045319.81	317895.56	0.
1188388.88	280493.09	0.
971120.13	298890.47	0.
1104033.63	264022.00	0.
902187.31	278188.00	0.
1025666.31	245784.56	0.
12951369.00	3746736.25	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-443363.00	-381489.19
854703.31	533824.69
735636.69	465783.22
929249.31	574764.44
679528.31	433865.47
859530.13	535065.31
630732.19	402787.81
797969.88	496810.75
582401.13	372035.88
737888.50	459458.78
540547.00	345370.88
799641.69	541227.50
7704465.00	4779505.00

DISCOUNT RATE IS 5.00% per quarter

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
398752.78	388272.59	416800.00
1297519.75	338012.81	0.
1175435.25	352769.56	0.
1320404.38	307163.38	0.
1066154.50	323659.22	0.
1197645.75	282125.13	0.
967033.69	294087.72	0.
1086300.13	256397.30	0.
877128.13	269961.69	0.
985306.31	235629.17	0.
795581.13	245316.17	0.
893701.94	214161.41	0.
12060964.00	3507556.50	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-443204.44	-381700.03
839486.38	524320.63
713937.94	452044.22
891103.56	551170.31
643876.00	411102.16
804738.44	500957.03
583495.38	372622.22
729420.06	454132.03
526032.13	336027.53
658536.31	410048.84
476673.69	304560.38
696758.13	471592.03
7120854.00	4406870.00

DISCOUNT RATE IS 6.25% per quarter

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
396400.25	385981.88	416800.00
1274689.75	332065.44	0.
1141168.00	342485.31	0.
1266829.50	294700.34	0.
1010861.69	306873.63	0.
1122174.13	264346.56	0.
895434.50	272313.44	0.
994036.63	234620.52	0.
793187.63	244126.56	0.
880530.69	210572.81	0.
702616.06	216650.53	0.
779985.69	186911.13	0.
11257915.00	3291648.25	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-443048.66	-381907.13
824715.56	515095.19
693124.69	438865.94
854947.44	528806.81
610483.38	389781.66
754026.44	469388.28
540293.38	345033.28
667467.75	415560.97

475691.22	303869.94
588508.81	366445.03
420973.53	268971.97
608101.31	411585.75
6595285.50	4071498.50

DISCOUNT RATE IS 7.50% per quarter

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OF COST ($)	PRESENT WORTH OF INVESTMENTS($)
394088.84	383731.22	416800.00
1252521.38	326290.44	0.
1108283.13	332615.97	0.
1216017.25	282879.97	0.
959033.44	291139.78	0.
1052259.25	247876.97	0.
829882.81	252378.33	0.
910554.19	214916.31	0.
718124.63	221023.73	0.
787932.13	188428.52	0.
621416.63	191612.83	0.
681823.31	163388.08	0.
10531937.00	3096282.00	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-442895.59	-382110.56
810372.69	506136.97
673151.00	426219.19
820655.75	507596.56
579183.13	369797.06
707048.38	440144.06
500740.34	319774.56
611411.63	380660.81
430674.38	275113.34
526619.88	327908.81
372322.78	237887.63
531570.88	359787.09
6120855.50	3768915.75

DISCOUNT RATE IS 10.00% per quarter

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
389584.81	379345.59	416800.00
1210065.38	315230.34	0.
1046381.88	314038.28	0.
1122005.50	261010.20	0.
864778.38	262526.19	0.
927277.19	218435.39	0.
714692.81	217347.52	0.
766344.75	180878.86	0.
590655.19	181791.31	0.
633342.81	151459.53	0.
488144.78	150518.66	0.
523423.75	125430.15	0.
9276698.00	2758012.25	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-442597.38	-382507.06
782904.06	488980.84
635553.31	402413.44
757209.8 1	468353.59
522260.19	333452.88
623068.69	387865.94
431236.22	275389.OO
514579.00	320373.44
354228.25	226279.78
423299.06	263574.38
292472.75	186869.17
408077.59	276202.22
5302292.00	3247247.75

DISCOUNT RATE **IS** 12.5Ø% **per quarter**

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
385231.78	375106.97	416800.00
1169954.75	304781.25	O.
989214.88	296881.41	O.
1037135.69	241267.08	O.
781601.81	237275.77	O.
819465.25	193038.50	O.
617562.00	187808.75	O.
647478.75	152823.14	O.
487950.19	150180.86	Ø.
511588.13	122342.75	O.
385540.88	118880.91	Ø.
404217.78	96864.34	O.
8236942.50	2477251.75	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-442309.13	-382890.22
756952.69	472772.28
600831.13	380428.38
699933.56	432926.78
472027.91	301380.53
550626.25	342769.88
372628.75	237962.05
434763.84	270681.09
292633.97	186933.59
341923.50	212904.50
230997.44	147590.84
315140.88	213299.16
4626151.50	2816759.50

DISCOUNT RATE IS 15.00% **per quarter**

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
381021.50	371007.34	416800.00
1132012.25	294896.97	O.
936326.56	281008.66	O.
960344.44	223403.25	Ø.
707997.44	214931.22	O.

726158.38	171058.53	0.
535347.81	162806.33	0.
549080.06	129598.30	0.
404799.88	124588.94	0.
415183.44	99288.23	0.
306086.88	94381.40	0.
313938.34	75230.31	0.
7368297.50	2242199.50	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-442030.31	-383260.81
732404.19	457439.97
568707.69	360088.78
648109.31	400872.16
427576.47	272999.19
487930.22	303741.03
323021.84	206282.92
368691.88	229545.09
242766.95	155078.70
277490.75	172784.34
183392.45	117174.66
244756.20	165660.17
4062818.00	2458406.75

DISCOUNT RATE IS **17.50% per quarter**

PRESENT WORTH OF [illegible]REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
376946.28	367039.22	416800.00
1096077.13	285535.63	0.
887313.94	266299.09	0.
890711.31	207204.63	0.
642690.06	195105.47	0.
645150.81	151975.88	0.
465506.66	141566.72	0.
467289.00	110293.31	0.
337171.00	103774.18	0.
338461.97	80940.83	0.
244216.22	75303.68	0.
245151.27	58746.59	0.
6636685.50	2043785.38	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-441760.47	-383619.56
709154.38	442918.75
538938.31	341239.69
601115.88	371805.53
388135.75	247817.02
433498.47	269856.75
280880.56	179371.33
313771.47	195352.02
202208.52	129170.11
226213.41	140855.63
146322.55	93489.64
191127.61	129362.33
3589606.00	2157619.00

DISCOUNT RATE IS 20.00% **per quarter**

PRESENT WORTH OF WI REV($)	PRESENT WORTH OF OP COST ($)	PRESENT WORTH OF INVESTMENTS($)
372999.09	363195.78	416800.00
1062003.63	276659.22	O.
841819.06	252645.25	O.
827437.13	192485.27	O.
584596.50	177469.64	O.
574609.Ø6	135358.61	O.
405969.78	123460.77	O.
399034.03	94183.22	O.
281923.47	86770.14	O.
277106.97	66268.21	O.
195780.16	60368.50	O.
192435.38	46114.07	O.
6015714.50	1874978.75	416800.00

PRESENT WORTH OF CASH FLOW BFIT($)	PRESENT WORTH OF CASH FLOW AFIT($)
-441499.09	-383967.00
687109.13	429149.94
511305.56	323743.47
558413.94	345393.28
353051.72	225416.58
386099.13	240350.22
244956.80	156430.28
267940.19	166817.78
169075.41	108004.80
185206.38	115321.91
117301.99	74947.59
150028.67	101545.03
3188990.00	1903154.00

APPENDIX D. STEAM INJECTION DATA

Table D.l is a listing of the raw steam injection data for the McManus Lease gathered from the California Department of Oil and Gas. Figures are in barrels of outer equivalent. 200 series wells are all injectors, while 100 series wells are producers that were on cyclic injection sometime during the life of the project. One-month, two-month, and three-month cyclic injection lags may easily be calculated by pushing forward in time the cyclic injection numbers. Also, test pattern injection rates may be determined by selecting the appropriate injector and cyclic injection wells comprising the test pattern.

TABLE D.1
WELL-BY-WELL MONTHLY INJECTION RATES IN
BARRELS OF WATER EQUIVALENT

1978

Well rouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	De
#1												
202												
203												
204												
205												
104								13,144	9,916			
105									16,262			
106									16,262			
107							2,920	19,326	2,538			
108							2,920	19,320	2,536			
109												
TOTAL							5,640	51,790	47,516			
#2												
206												
209												
110												
115												
121												
TOTAL												
#3												
207												
206												
210												
211												
112					3,433	13,551	11,095	2,274				
114					4,194	16,466	12,940					
118					2,133	6,392	7,641				2,528	
124					3,127	12,294	7,098					
125					1,815	7,602	6,228					
126					1,308	5,166	7,261	1,056			1,275	
TOTAL					16,110	63,471	54,463	3,332			3,803	
#4												
212												
#5												
213												
214												
215												
127												
TOTAL												

Well rouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#6												
216												
217												
218												
210												
130												
131												
332												
133												
134												
138												
139												
140												
141												
142												
TOTAL												

TABLE D.1 (Continued)

1979

Well rouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1												
202					1,020							
203					952			23.097	19.138	19.709	13,114	14.32
204					1,460			25.150	24,115	22.259	19,270	20.61
205					1,402			23.011	23,660	22,122	18.830	22.2:
104									8.500			
105										6,022	8.276	
106										11,073		
107												
108												
109												
TOTAL					4.834			71.258	75.413	81.185	59,940	57,18
#2												
206												
209												
110												
115												
121												
TOTAL												
#3												
207	7,840	7.521	7.143	7.085	6.082	9.686		9,236	8,863	8,413	8.358	9,63
208	14.019	15.304	15,344	10.434	13.603	15.907		21,730	18.291	13.871	13.865	18.34
210	11,394	9,508	9,114	10.187	8,211	10.580		12,973	11,582	0.595	16.718	11.72
211	8,444	8,631	8.288	9,054	7,237	8.430		12.326	12,098	7,749	8.260	8.32
112												
114												
118			2.183									
124											5.864	
125			1,902									
126												
TOTAL	11,697	40,964	43,974	36,760	35,133	43.603		56,265	50.834	39,628	47,065	48,02
t4												
212									11,640		8,210	5.64
#5												
213												
214												
215												
127												
TOTAL												

Well rouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#6												
216									1,353	13,787	12.963	11.59
217									1,510	16.936	15,426	13,64
218									1,980	16.839	15.844	13.13
219									1.510	13.309	14.479	12.71'
130												
131												
132												
133												
134						610		17,929	5,829			
138						11.258					1,038	
139						2,001	16.756	1,198				
140						777	18.756	1.198				
141							18.756	1,198				
142								17,929	11,460			
TOTAL						14,646	56.268	39.452	23.642	60,871	59,750	51.08'

TABLE D.1 (Continued)

1980

Well Grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1												
202												
203	21,566	19,220	14.197	14.932	18,010							7.45'
204	24,404	27,770	17.414	20,193	23,671							6.31:
205	22,809	20.556	15,243	20,183	24,494							11.271
104												
105								7,303				
106												
107												
108												
109		3,529	1,296									
TOTAL	68.779	71,075	48.150	55.308	66.175			7.303				25,04
#2												
206												
209												
110												
115												
121												
TOTAL												
#3												
207	10,233	6.748	5,209	7.379	8.668							4.45
208	14,279	11,318	10,150	17,646	23,920							9,96
210	12.728	10.419	7,378	8,563	12,430							5.47'
211	11.221	10,131	6.989	9,032	12.381							4.791
112												
114												
118					7,484			7.089				
124								202	3,778			22
125												
126								2,714	4.838			
TOTAL	48.461	38.616	29,726	42.620	64.883			10,005	8,614			24,91
#4												
212												
#5												
213												
214												
215												
127												
TOTAL												

Well rouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#6												
216	14,037	12,209	20,973	15.664	10.960							6,341
217	15.583	12,959	25.483	25,339	10.849							9,296
218	15.128	12,749	20,579	20,376	9.415							7,443
219	14,705	12,501	20,128	17,771	13.327							9,615
130	4,944	1,636										
131												
132								3.637				
133		2.011			4.631			2.714	4,836			
134								200	3,776			225
138								7,649				
139					7.484							
140									4,976			
141												
142												
TOTAL	64.397	54,062	87.163	79.150	56,666			14,200	13,588			32,920

TABLE D.1 (Continued)

1981

Well Grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1												
202												
203	9.685	6,509	4.087	5,946			6,021	5,774	5,377	4,599	3.232	3,76
204	9,126	1.245	7.031	4.689			5,470	5,226	5,075	2.036	624	
205	3.396	2,912		7.900	5.961	4,143			5.801	2.461	454	3,30
104												
105											2.634	416
106												3.312
107												
100												
109												
TOTAL	22,207	12,666	11.918	18,535	5,964	4,143	11,491	11,000	16,253	9,896	6,944	10,80
#2												
206											7,423	9,09
209											7.423	9,09
110											5.040	
I15												
121									1,235			
TOTAL									1.235		19,886	18.19
#3												
207	6,106	3,432	8,843				6.546	5,503	5,652	2,742	1.278	
208	4.347	5.462	8.945	7,506			5,764	2,630		3,555	2.977	3.77
210	4.607	3.002	4.603	5,667			4,493	4,299	5,787	5,724		
211	4,924	2.927	4,709	4.043			4.940	4.160	5.242	3,470		
112												
114												
118	3,660									5.515		
124	3,594			1,018								
125										754	4.566	
126		4,521										
TOTAL	27,318	19,344	27,300	19,034	127.300	19,034	22.193	16,592	16.681	21,760	8,821	3,77
212											7.423	9.09
#5												
213										9,330	7,427	9.09
214										3.828	6.255	9.09
215										4.204	7,422	9,09
127									1,550			
TOTAL									1,550	11,422	21,099	27.28

Well Grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#6												
216	7.361		5.576	5,817			9.033	5.705	6,137	4,154	2.137	3,779
217	9,757	8.255	5,674	8,002			10,161	7,529	8,908	8,165	3.231	3.778
218	7.250	5.985	4,472	7,635			9,605	8.073	7,898	6.549	2,976	359
219	6,021	8.294	9,008	8.223			9,900	7.746	7,674	3,699	1,275	3,418
130												3,166
131							881				3,992	
132	994						681				5.798	
133		1,672										
134	3,592											
138												3,402
139										3.047		
140												
141												
142												
TOTAL	34,975	24,206	25,180	29,677			40,061	29,053	30,617	25.614	15.809	17,902

TABLE D.1 (Continued)

1982

Well Grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1												
202												
203	4,404	4,095	4,448	4.458	3.382	4,033	4,833	5.096	4,898	4,898	4.326	4.78
204	3,504	4.188	4,523	4,783	4,591	4,364	5,241	5,550	1,769	1,769	1.242	1.54
205	4.404	4,151	4.552	4,769	3,915	4.297	5.174	5,457	9,049	9,049	9,279	10,25
104				759	4,352							
105				5.187								
106				4,887				5.483				
107					4,887							
108												
109												
TOTAL	12.312	12.434	13,523	24,844	21,107	12.684	15.248	21.586	15.716	15,716	14.847	18.59
#2												
208	5.780	4.184	4,502	4,723	4,210	4,345	5.177	5.519	5.125	5,125	4,616	5,140
209	5,780	4.204	4.550	4.813	3.885	4,402	4.675	5.098	4,944	4.844	4,561	4.97
110				720	4.050			4.909				
115	6.585											
121	8,009											
TOTAL	20,134	8,388	9,052	10,256	12,125	8,747	8.852	15.608	10,069	10.069	9,167	10.11
#3												
207	3,504	4.180	4,513	4,758	3.176	4,343	4.628	5.043	4,877	4.977	4.687	5.245
208	4,405	4,101	4.548	1.637	4.253	4,208	4,503	4,906	4,735	4,735	4,629	5.163
210	3.504	4.184	4.508	4,755	3,915	4,359	4,686	4,750	5.026	5,026	4.686	5,262
211	3,462	4,102	4.533	4,609	3,886	4,235	4.483	4.842	4,864	4,864	4,545	4.975
112					4,859							
114												
118					4,830							
124	4.226			5,053								
125												
128												
TOTAL	19,101	16.567	18,102	23,612	24,919	17,145	18,298	19.668	19.802	19,602	18,547	20.64
#4												
212	6,780	4,184	4,520	4.687	4,541	4.409	4.452	4,868	5.057	5,057	4.782	5.37
#5												
213	6,780	4,190	4.533	4,773	4.179	4.417	4,727	5.115	5.048	5.048	4,714	5.344
214	5,780	4,151	4,559	4.879	4.065	4.911	4.541	4,964	4.753	4.753	4,610	5,118
216	5,777	4,181	4.588	4.714	4,252	4.391	4.876	5.107	5,009	5.009	4,690	5,283
127		3,754	1,288									
TOTAL	17,337	10,278	14.986	14.643	12.496	13,119	13,944	15.186	14.810	14.810	14.014	15.74

Well rouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#6												
216	4,407	4,192	4,539	4,831	4,672	4,429	4,750	5,108	5,066	5,066	4,731	5,414
217	4,447	4,199	4,532	4,828	4,136	4,425	4,730	5,121	5,061	5,061	4,731	5,397
218	3,504	4,208	4,541	4,813	4,666	4,282	4,469	4,858	4,986	4,986	4,693	5,274
219	4,447	4,202	4,533	4,819	4,103	4,392	4,687	5,084	5,033	5,033	4,719	6,303
130								5,709				
131												
132	1.376	4,030										
133												
134												
138												
139				720	4,583							
140												
141												
142												
TOTAL	18.181	20,891	18,144	20,011	22.160	17.528	18,836	25.880	20.146	20,146	18,874	21.981

TABLE D.1 (Continued)

1983

Well Grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1												
202												
203	4.849	4,037	5.045	4.365	4,251	3.684	4,616	1,730	1,306	2,332		
204	1,743	1,528	1,445	1,022	960	877	1,500	499	906	1,292		
205	0,446	8,637	11,101	9,742	9,795	8.740	10.781	4,086	3,365	5,386		
104												
105		160	7,424									
106												
107					1,201	7,011						
108												
109												
TOTAL	7.038	14.382	25.015	15.129	16,207	20,312	16.897	6.315	5,577	9,010		
#2												
206	5,142	4,229	5.381	4,650	5.507	3.941	4.934	1.850	1,506	2,334		
209	5.017	4,188	5,287	4,603	4,419	3,888	4,901	2,124	1,464	2.306		
110												
115												
121	6,209	1,116										
TOTAL	6,368	9,533	10,668	9,253	9,926	7.029	8.835	3,974	2.970	4,640		
#3												
207	6,162	4.275	5.486	4,760	4.542	4.051	5,036	2,188	1.522	2,340		
206	5,091	4,213	5,405	4,722	4.546	3,938	5,135	2,256	1,591	2,416		
210	5.253	4,362	5.927	5.125	5,101	4.540	5.871	2,396	1.872	2,602		
211	5.068	4,206	5,308	4,453	4,422	3.822	4.856	2,117	1.458	2,341		
112												
114												
118												
124					1,341	4,931						
125												
126												
TOTAL	10,574	17,056	22,127	19,150	19.952	16.452	20,898	8,967	6.243	9.689		
#4												
212	5.317	4,411	5.590	4.821	4,609	4,070	5,066	2,213	1.545	2,417		
#5												
213	5,321	4,394	5,521	4,806	4,583	4,073	5.110	2,202	1,545	2,380		
214	5,162	4,270	5,405	4.697	4,151	3,964	4.883	2.162	1.519	2,353		
215	5.248	4,326	5.992	4,742	4,541	4,039	5.014	2,199	1,536	2,360		
127		180	6,877									
TOTAL	5,731	13,170	23.285	14,245	13,275	12,076	15,117	6,563	4,600	7,093		

Well Grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#6												
216	5,333	4,402	5,562	4,800	4.584	4,116	5,132	2,215	1.327	2,365		
217	5,343	4.402	5,564	4,810	4,621	4,122	5.145	2.261	1.545	2.388		
218	5,160	4,172	5,220	4,479	4,341	3.875	4,872	2.127	1.506	2.350		
218	5,282	4.388	5,531	4.792	4.577	4,070	5.087	2.208	1.552	2.387		
130												
131												
132	5.103	1.187										
133	6,595	1,187										
134												
138		180	6.659									
139												
140												
141							5,726	5,593				
142												
TOTAL	32,816	19,918	28,536	18,875	18,123	16,183	25.962	14.404	5,930	9,510		

APPENDIX E. WELLBORE HEAT LOSS CALCULATIONS

E.1 Calculation of Downhole Steam Quality

Using the steam tables, the following properties for saturated liquid of the five scenarios were determined.

Code #	Pressure (psia)	Temperature (°F)	L_v (Btu/lb$_m$)	C_w (Btu/lb$_m$ °F)
1	95	324	891.6	1.01
2	130	347	872.8	1.01
3	165	366	857.3	1.01
4	215	388	037.3	1.02
5	265	406	820.0	1.02

Using 75% quality of the steam injected for the 95 psia case, wellhead enthalpy/lb$_m$ was determined as follows:

$$\text{enthalpy} / \text{lb}_m = C_w \Delta T + f_s L_v = 925.3 \text{Btu} / \text{lb}_m$$

This number was assumed identical for all cases. We were therefore able to calculate steam quality, f_s, from

$$f_s = \frac{925.3 - C_w \Delta T}{L_v} \tag{E.1}$$

This gave

		f_s
95	psia	0.75
130	psia	0.739
165	psia	0.728
215	psia	0.718
265	psia	0.710

E.2 Inputs for Osman.f

The inputs for the Osman.f wellbore heat loss computer program used to determine downhole heat input parameters are shown in Table E.l.

TABLE E.1
OSMAN.F INPUTS

Tubing inner radius	0.063125 ft.
Tubing outer radius	0.098956 ft.
Casing inner radius	0.269 ft.
Casing order radius	0.291667 ft.
Wellbore radius	0.401642 ft.
Straight hole	
Well depth	500 ft.
Length increment	100 ft.
No insulation	
Emissivity of tubing	0.9
Emissivity of casing	0.9
Earth thermal conductivity	1.36 Btu/ft-hr-°F
Cement thermal conductivity	0.5 Btu/ft-hr-°F
Mean earth surface temperature	70°F
Thermal diffusivity of earth	0.033 ft^2/hr
Temperature gradient of earth	0.011 °F/ft.
Dry annulus	
Natural convection	
Atmospheric annulus pressure	
No dry earth zone	
Time of injection	720 hrs. (1 month)
	8760 hrs (1 year)
	52560 hrs (6 years)

E.3 Downhole Heat Content Codes

Table E.2 lists the monthly downhole heat content codes for each well grouping under each injection scenario. The numbers refer to the code listings given in Appendix E. 1.

TABLE E.2
DOWNHOLE HEAT CONTENT CODES

1978

1 month lag in Cyclic injection Well grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1								5	5	5	5	5
#2												
#3						5	5	5	5	5	5	5
#4												
#5												
#6												
2 month lag in Cyclic injection Well Grouping												
#1									5	5	5	5
#2												
#3							5	5	5	5	5	5
#4												
#5												
#6												
3 month lag in Cyclic injection Well grouping												
#1										5	5	5
#2												
#3								5	5	5	5	5
#4												
#5												
#6												

TABLE **E.2** **(Continued)**

1979

1 month lag in Cyclic injection Well grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1	5	5	5	5	5	5	5	5	5	5	5	5
#2												
#3	5	5	5	5	5	5	5	5	5	5	5	5
#4									5	5	5	5
#5												
#6												
2 month lag in Cyclic injection Well Grouping												
#1	5	5	5	5	5	5	5	5	5	5	5	5
#2												
#3	5	5	5	5	5	5	5	5	5	5	5	5
#4									5	5	5	5
#5												
#6								5	5	5	5	5
3 month lag in Cyclic injection Well grouping												
#1	5	5	5	5	5	5	5	5	5	5	5	5
#2												
#3	5	5	5	5	5	5	5	5	5	5	5	5
#4									5	5	5	5
#5												
#6									5	5	5	5

TABLE E.2 (Continued)

1980

1 month lag in Cyclic injection Well grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1	4	4	4	4	4	4	4	4	4	4	4	4
#2												
#3	4	4	4	4	4	4	4	4	4	4	4	4
#4	4	4	4	4	4	4	4	4	4	4	4	4
#5												
#6	4	4	4	4	4	4	4	4	4	4	4	4
2 month lag in Cyclic injection Well Grouping												
#1	4	4	4	4	4	4	4	4	4	4	4	4
#2												
#3	4	4	4	4	4	4	4	4	4	4	4	4
#4	4	4	4	4	4	4	4	4	4	4	4	4
#5												
#6	4	4	4	4	4	4	4	4	4	4	4	4
3 month lag in Cyclic injection Well grouping												
#1	4	4	4	4	4	4	4	4	4	4	4	4
#2												
#3	4	4	4	4	4	4	4	4	4	4	4	4
#4	4	4	4	4	4	4	4	4	4	4		4
#5											4	
#6	4	4	4	4	4	4	4	4	4	4	4	4

TABLE **E.2 (Continued)**

1981

1 month lag in Cyclic injection Well grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1	3	3	3	3	3	3	1	1	1	1	1	1
#2										1	1	2
#3	3	3	3	3	3	3	1	1	1	1	1	2
#4	3	3	3	3	3	3	3	3	3	3	1	1
#5										2	1	2
#6	3	3	3	3	3	3	2	2	2	1	2	2
2 month lag in Cyclic injection Well Grouping												
#1	3	3	3	3	3	3	1	1	1	1	1	1
#2											2	2
#3	3	3	3	3	3	3	1	1	1	1	1	2
#4											1	1
#5										1	2	2
#6	3	3	3	3	3	3	2	2	2	1	1	2
9 month lag in Cyclic injection Well grouping												
#1	3	3	3	3	3	3	1	1	1	1	1	1
#2											1	2
#3	3	3	3	3	3	3	2	1	1	1	1	1
#4	3	3	3	3	3	3					1	1
#5										1	1	2
#6	3	3	3	3	3	3	2	2	2	2	1	1

TABLE E.2 (Continued)

1982

1 month lag in Cyclic injection Well grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1	2	1	1	1	2	2	1	1	2	1	1	1
#2	1	2	1	1	1	2	1	1	2	1	1	1
#3	1	2	1	1	2	2	1	1	1	1	1	1
#4	1	1	1	1	1	1	1	1	1	1	1	1
#5	1	1	2	2	1	1	1	1	1	1	1	1
#6	2	2	2	1	1	2	1	1	2	1	1	1
2 month lag in Cyclic injection Well Grouping												
#1	2	2	1	1	1	2	2	1	1	2	1	1
#2	2	1	2	1	1	1	2	1	1	2	1	1
#3	2	1	2	1	2	2	1	1	1	1	1	1
#4	1	1	1	1	1	1	1	1	1	1	1	1
#5	1	1	2	2	1	1	1	1	1	1	1	1
#6	2	2	2	2	1	1	2	1	1	2	1	1
3 month lag in Cyclic injection Well grouping												
#1	1	2	2	1	1	1	2	2	1	1	2	1
#2	1	2	1	2	1	1	1	2	1	1	2	1
#3	2	2	1	2	1	1	2	2	1	1	1	1
#4	1	1	1	1	1	1	1	1	1	1	1	1
#5	1	1	1	1	2	2	1	1	1	1	1	1
#6	2	2	2	2	2	1	1	2	1	1	2	1

TABLE E.2 (Continued)

1983

1 month lag in cyclic injection Tell grouping	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
#1	1	1	1	2	1	1	2	1	1	1		
#2	1	2	2	1	1	1	1	1	1	1		
#3	1	1	1	1	1	2	2	1	1	1		
#4	1	1	1	1	1	1	1	1	1	1		
#5	1	1	1	2	1	1	1	1	1	1		
#6	1	2	2	2	1	1	1	1	1	1		
2 month lag in cyclic injection Well grouping												
#1	1	1	1	1	2	1	2	1	1	1		
#2	1	1	2	2	1	1	1	1	1	1		
#3	1	1	1	1	1	1	2	1	1	1		
#4	1	1	1	1	1	1	1	1	1	1		
#5	1	1	1	1	2	1	1	1	1	1		
#6	1	1	2	2	2	1	1	1	1	1		
3 month lag in cyclic injection Well grouping												
#1	1	1	1	1	1	2	1	1	1	1		
#2	1	1	1	2	2	1	1	1	1	1		
#3	1	1	1	1	1	1	1	1	1	1		
#4	1	1	1	1	1	1	1	1	1	1		
#5	1	1	1	1	1	2	1	1	1	1		
#6	1	1	1	2	2	2	1	1	1	1		

APPENDIX F. NET TO GROSS THICKNESS RATIOS OF SELECTED WELLS

F.1 Total Lease

Table F.1 below contains net to gross thickness ratios (in feet) of selected wells on the McManus Lease well groupings.

TABLE F.1
NET TO GROSS THICKNESS—TOTAL LEASE

$$\frac{h_n}{h_t}$$

Well grouping		All slices	Top slice only	Top two slices only
#1				
109		310/350	63/63	153/162
205		315/352	64/64	121/133
108		330/377	62/62	133/141
112		273/315	82/90	144/160
113		247/340	77/93	120/157
114		322/360	65/68	140/150
106		325/370	73/77	164/172
104		352/380	53/53	121/132
	Avg	307/356	67/71	137/151
#2				
109		310/350	63/63	153/162
114		322/360	65/68	140/150
120		265/335	04/94	148/166
	Avg	299/348	71/75	147/159
#3				
207		250/296	68/75	122/154
208		217/295	67/67	128/153
211		254/288	55/62	123/161
112		273/315	82/90	144/160
113		247/340	77/93	120/157
114		322/360	65/68	140/150
118		318/342	70/70	137/137
119		194/255	52/64	118/150
120		265/335	04/94	148/166
125		253/302	84/92	119/155
126		174/307	86/95	140/162
	Avg	252/312	72/79	131/155

#4				
120		265/335	84/94	148/166
126		174/307	86/95	140/162
	Avg	220/321	85/95	140/164
#5				
214		209/233	93/93	139/147
125		253/302	84/92	119/155
126		174/307	86/95	140/162
131		236/295	53/53	140/169
132		303/340	56/56	137/157
133		238/325	45/53	99/151
134		235/290	41/56	106/158
	Avg	235/299	65/71	126/157
#6				
131		236/295	53/53	140/169
132		303/340	56/56	137/157
133		238/325	45/53	99/151
134		235/290	41/56	106/158
138		253/290	58/58	127/143
141		206/290	99/110	102/162
	Avg	245/305	59/64	119/157

F.2 <u>Test Pattern</u>

Table F.2 below contains net to gross thickness ratios (in feet) of selected wells within the test pattern groupings on the McManus Lease.

TABLE F.2
NET TO GROSS THICKNESS–TEST PATTERN

$$\frac{h_n}{h_t}$$

Well grouping		All slices	Top slice only	Two two slices only
#1				
205		315/353	63/63	121/133
113		247/340	77/93	120/157
114		322/360	65/68	140/150
	Avg	295/351	68/75	127/147

#2				
114		322/360	65/68	140/150
120		265/335	84/94	148/166
	Avg	294/348	75/81	144/158
#3				
207		250/296	68/75	122/154
208		217/295	67/67	128/153
211		254/288	55/62	123/161
113		247/340	77/93	120/157
114		322/360	65/68	140/150
119		194/255	52/64	118/150
120		265/335	84/94	148/166
	Avg	250/310	67/75	128/156
#4				
120		265/335	84/94	148/166
	Avg	265/335	84/94	148/166

APPENDIX G. CALCULATIONS FOR THERMAL PROPERTIES

G.1 Steam Zone

Two types of layers were assumed to exist in the steam zone. One was sand, with a porosity of 25%, an initial oil saturation of 50%, a final oil saturation of 10% and a density of 165.4 lb_m/ft^3. The other was silt with a porosity of 30%, a water saturation of 100%, and a density also of 165.4 lb_m/ft^3. Temperature conditions were assumed to be average between steam and ambient temperature, or 212.5°F.

Volumetric heat capacity was all that was required for the steam zone layers. For sand, the following equation was used.

$$M_R = M_\sigma(1-\varphi) + M_o\varphi S_{or} + M_w\varphi S_{wr} + \varphi S_{st}\left[\frac{\rho_{st} L_v}{\Delta T} + \rho_{st} C_w\right] \tag{G.1}$$

The subscript ***st*** indicates steam.

All M values were determined using the relationship

$$M = c\rho \tag{G.2}$$

For the rock matrix at 212.5°F , C_σ = 0.22 Btu/lb_m-°F and ρ_σ = 165.4 lb_m/ft^3. This gave M_σ = 36.38 Btu/ft^3–°F.

For oil, C_o was determined from

$$C_o = \frac{(0.388 + 0.00045T)}{\sqrt{\gamma_o}} \tag{G.3}$$

with T = 212.5°F and γ_o = 0.94 for 14° oil. C_o was therefore 0.499 Btu/$lb_m ft^3$. Since ρ_o = 58.66/lb_m/ft^3, M_o from **Eq.** (G.2) gave 29.27 Btu/$ft^{3-°F}$.

For water, ρ_w = 59.79 lb_m/ft^3 and C_w = 1.01 Btu/lb_m-°F; therefore, M_w = 60.39 Btu/ft^3–°F, from Eq. (G.2).

Finally, the following properties were determined for steam at 350°F from the steam tables

$$L_v = 870.55 \text{ Btu}/\text{lb}_m/\text{f 2}$$
$$\rho_{st} = 0.299 \text{ lb}_m^3/\text{ft}$$
$$C_w = 1.02 \text{ Btu}/\text{lb}_n - {}^\circ\text{F}$$

Combining these results into Eq. (G.1), and assuming that S_{wr} = 0.45 and S_{st} = 0.45, gives for sand in the steam zone

$$M_R = 34.95 \text{ Btu}/\text{ft}^3 - {}^\circ F$$

For silt, the following equation applied

$$M_R = M_\sigma(1 - \varphi) + M_w \varphi \tag{G.4}$$

All properties were determined at the average temperature, 212.5°F. C_σ and ρ_σ were identical to the sand, so M_σ was also 36.38 Btu/ft^3$-{}^\circ F$. M_w was also the same, 60.39 Btu/ft^3$-{}^\circ F$. Then, from Eq. (G.4), M_R = 43.58 Btu/ft^3$-{}^\circ F$ for silt in the steam zone.

G.2 <u>Overburden and Underburden</u>

Three thermal properties had to be determined for the overburden and underburden. These were volumetric heat capacity, thermal diffusivity, and thermal conductivity. First, let's look at volumetric heat capacity.

Again, two different layers were assumed: sand and silt. The sand, however,,was of two types: (1) saturated with 50%oil and 50%water, and (2) saturated with water only. Both were assumed to exist at ambient conditions of 75°F with a porosity of 25%. For the case of only water, Eq. (G.4) applied. Using Eqs. (G.2) at 75°F, M_w was determined as 62.4 Btu/ft^3-°F. Similarly, for the rock matrix with C_σ = 0.20 Btu/lb$_m$-ft^3 and ρ_σ = 165.4 lb$_m$/ft^3, M_σ became 33.07 Btu/ft^3°F.

Applying Eq. (G.4), the resultant volumetric heat capacity, M_s, became 40.40 Btu/ft^3-°F.

When both water and oil in equal proportions were assumed to exist in the sand layer, the following equation was applied.

$$M_s = M_\sigma(1 - \varphi) + M_w \varphi S_w + M_o \varphi s_o \tag{G.5}$$

The first two expressions on the right-hand side of the equation utilized the same constants as the previous case. For oil, C_o was determined at 75°F from **Eq.** (G.3). It was 0.424 Btu/lb$_m$-°F. Since γ_o at 75°F was 0.99, ρ_o becomes 61.75 lb$_m$/ft^3. Hence M_o = 26.19 Btu/ft^3-°F from Eq. (G.2). Plugging into Eq. (G.5) gave

$$M_s = 35.88\ Btu/ft^3 - °F$$

The final calculations involved thermal conductivity and thermal diffusivity. The key relationship here was

$$\alpha = \frac{K}{M} \tag{G.6}$$

K, thermal conductivity, was determined by a three-step process. For the matrix

$$K_m = 4.45 f_q + 1.65(1 - f_q) \tag{G.7}$$

where f_q was fractional volume of quartz in the matrix. Then, for the reservoir at 125°F

$$K_R = 0.735 - 1.30\varphi + 0.39\ K_m \sqrt{S_w} \tag{G.8}$$

Finally, at reservoir temperature, T,

$$K_R(T) = K_r - 1.28 \times 10^{-3}(T - 125)(K_R - 0.82) \tag{G.9}$$

For silt at ambient conditions, f_q = 0.5. *So*, plugging the values established in the previous calculation into these equations yielded

$$K_m = 3.05 \text{ Btu/ft-hr-}^\circ\text{F}$$
$$K_R = 1.53 \text{ Btu/ft-hr-}^\circ\text{F}$$
$$K_R(T) = 1.58 \text{ Btu/ft-hr-}^\circ\text{F}$$
$$\alpha = 0.0377\ ft^2/hr = 0.906\ ft^2/Day$$

The same f_q value was used for the two sand scenarios. This resulted in

$$K_m = 305 \text{ Btu/ft-hr-}^\circ\text{F}$$
$$K_R = 1.25 \text{ Btu/ft-hr-}^\circ\text{F}$$
$$K_R(T) = 1.28 \text{ Btu/ft-hr-}^\circ\text{F}$$
$$a = 0.0356\ ft^2/hr = 0.85.5\ ft^2/Day$$

for sand with water only and

$$K_m = 3.05\ Btu/ft\text{-}hr\text{-}^\circ F$$
$$K_R = 1.60\ Btu/ft\text{-}hr\text{-}^\circ F$$
$$K_R(T) = 1.65\ Btu/ft\text{-}hr\text{-}''F$$
$$a = 0.0408\ ft^2/h = 0.980\ ft^2/Day$$

for sand with both water and oil.

APPENDIX H. COST CALCULATIONS FOR LEASE-WIDE ECONOMICS

H.1 Surfactant Injection System Utility Costs

Two pumps are used in this operation, a high pressure piston pump, and a charge pump. The total power rating for both pumps is 7 Hp, or approximately 5.2 Kw. Each quarter of activity is comprised of 2,189 hrs, thereby using 11,383 Kw-hrs of power per quarter. At a 6/84 cost of 8.18¢/Kw-hr, this yields a quarterly cost of $931 in current dollars.

H.2 Nitrogen Injection System Utility Costs

The MSA4 portable nitrogen generator utilizes 825 scf/hr of natural gas. Each quarter of activity is comprised of 2,189 hrs, thereby requiring 1,805,925 scf of gas. At a 6/84 cost of $7.18/mscf. this yields a quarterly cost of $12,967 in current dollars.

The power requirement of the generator is 45 Kw. This gives 98,505 kw-hr per quarter, which in current dollars is $8,058/quarter.

The centrifugal pump used to feed cooling water to the generator has a rating of 1 Hp. On a quarterly basis, this yields a 3,266 Kw-hr power requirement, the cost of which in current dollars is $267/quarter. Total quarterly utility cost for the nitrogen injection system is, in current dollars, $21,292.

H.3 Calculation of Quarterly Cost Stream

Tangible costs incurred in Quarter #1

Surfactant injection system	$170,800
Nitrogen injection system	246,000
TOTAL	$416,800

Tables H. 1 and H.2 below list the quarterly utility and manpower costs:

TABLE H. 1
QUARTERLY COSTS FOR UTILITIES
(escalated at 1.5%/quarter)

Quarter	Surfactant Plus Injection System	Nitrogen Injection System
1st	$931	$21,292
2nd	945	21,611
3rd	959	21,936
4th	974	22,265
1st	988	22,599
2nd	1,003	22,938
3rd	1,018	23,282
4th	1,033	23,631
1st	1,049	23,985
2nd	1,064	24,245
3rd	1,080	24,710
4th	1,097	25,081

TABLE H.2
QUARTERLY COST FOR MANPOWER
(escalated at 6%/year)

Quarter	Manpower Costs
1st	$65,000
2nd	65,000
3rd	65,000
4th	65,000
1st	68,900
2nd	68,900
3rd	68,900
4th	68,900
1st	73,034
2nd	73,034
3rd	73,034
4th	73,034

Bimonthly surfactant + royalty costs are $207,092, $207,092, and $172,576, every six months. Since each six months period represents two quarters, quarterly figures are easily calculated as

1st quarter = 6207,092 + 1/2($207,092) = $310,638

2nd quarter = 1/2 (1207,092) + $172,576 = $276,122

These are repeated every two quarters, leading to the surfactant and royalty schedule shown in Table H.3.

TABLE H.3
QUARTERLY COSTS FOR SURFACTANT AND ROYALTY

Quarter	Surfactant plus royalty costs
1st	$310,638
2nd	276,122
3rd	310,638
4th	276,122
1st	310,638
2nd	276,122
3rd	310,638
4th	276,122
1st	310,638
2nd	276,122
3rd	310,638
4th	276,122

The quarterly test/control items costs are shown in Table H.4.

TABLE H.4
QUARTERLY COST FOR TEST/CONTROL ITEMS
(escalated at 1.5%/quarter)

Quarter	Reservoir engineering study	Logs and tests
1st	$100,000	$9,100
2nd		9,237
3rd		9,375
4th		9,516
1st		9,658
2nd		9,803
3rd		9,950
4th		10,100
1st		10,251
2nd		10,405
3rd		10,561
4th		10,719

APPENDIX I. INCREMENTAL PRODUCTION CALCULATION FOR LEASE-WIDE ECONOMICS

1.1. Expected Case

First, incremental production/gallon of surfactant per injection was calculated

$$\frac{27{,}000 \text{ Bbls}}{69{,}425 \text{ gallons}} = 0.3889 \text{ Bbls oil / gallon surfactant}$$

Over each two month injection period, the number of gallons injected per injector was:

$$0.25 \text{ gpm} \times 60 \frac{\text{min}}{\text{hr}} \times 24 \frac{\text{hrs}}{\text{day}} \times 304 \frac{\text{days}}{\text{month}} \times 2 \text{ months} = 21{,}888 \text{ gallons}$$

Therefore, incremental production due to each two month slug per injection is

$$21{,}888 \text{ gallons} \times 0.3889 \frac{\text{Bbls oil}}{\text{gallon}} = 8{,}512 \text{ Bbls}$$

Spreading this evenly over the five month response period gave 1,702 Bbls per month. For the first two reservoir units in which six wells are included, this means 10,215 Bbls/month. The third unit has only five welis, and therefore produced only 8,512 Bbls/month. Table I-1 indicates how these production figures are scattered, then summed to get the total lease-wide production.

The high and low cases were exact ratios of the expected case, based on the total incremental production from the pilot. In the high case, each quarterly figure was multiplied by 31,400/27,000, while in the low case, each was multiplied by 14,000/27,000.

TABLE 1.1
INCREMENTAL PRODUCTION FOR EXPECTED CASE

Month #	Reservoir Segment #1 (Barrels)	Reservoir Segment #2 (Barrels)	Reservoir Segment #3 (Barrels)	Monthly Total (Barrels)	Quarterly Total (Barrels)
1				0	
2	10,215			10,275	
3	10,215			10,215	20,430
4	10,285	10,215		20,430	
5	10,215	10,215		20,430	
6	10,215	10,215	8,512	28,942	69,802
7		10,215	8,512	18,727	
8	10,215	10,215	8,512	28,942	
9	10,215		8,5 12	18,727	66,396
10	10,215	10,215	8,512	28,942	
11	10,215	10,215		20,320	
12	10,215	10,215	8,512	28,942	78,314
1		10,215	8,512	18,727	
2	10,215	10,215	8,512	28,942	
3	10,215		8,512	18,727	66,396
4	10,215	10,215	8,512	28,942	
5	10,215	10,215		20,430	
6	10,215	10,215	8,5 12	28,942	78,314
7		10,215	8,512	18,727	
8	10,215	10,215	8,512	28,942	
9	10,215		8,5 12	18,727	66,396
10	10,215	10,215	8,512	28,942	
11	10,215	10,215		20,430	
12	10,215	10,215	8,512	28,942	78,314
1		10,215	8,512	18,727	
2	10,215	10,215	8,512	28,942	
3	10,215		8,512	18,727	66,396
4	10,215	10,215	8,512	28,942	
5	10,215	10,215		20,430	
6	10,215	10,215	8,512	28,942	78,314
7		10,215	8,512	18,727	
8	10,215	10,215	8,512	28,942	
9	10,215		8,5 12	18,727	66,396
10	10,215	10,215	8,5 12	28,942	
11	10,215	10,215		20,430	
12	10,215	10.215	8,5 12	28,942	78,314